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Fresh Water Reduction Technologies and Strategies for Hydraulic Fracturing:

Case Study of the Eagle Ford Shale Play, Texas

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Fresh Water Reduction Technologies and Strategies for Hydraulic Fracturing:

Case Study of the Eagle Ford Shale Play, Texas

by

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Thesis

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Dedication

I would like to dedicate this thesis to my dad, Denny Leseberg. You have been the most encouraging and supportive person in my life, always pushing me to do my best and strive for the top. You are the best role model anyone could ever have. I attribute my time and success here at The University of Texas at Austin to you, and what an incredible experience it has been. I couldn’t have done it without your support. I am forever grateful, Dad. Now we’re both Texas Exes!

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Abstract

Fresh Water Reduction Technologies and Strategies for Hydraulic Fracturing:

Case Study of the Eagle Ford Shale Play, Texas

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The University of Texas at Austin, 2013

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Hydraulic fracturing has unlocked a tremendous resource across the United States and around the world—shale. However, these processes have also come with a myriad of potential environmental effects, including a substantial demand for water. Hydraulic fracturing can require anywhere between two and four million gallons per well. The need for such large quantities of water can produce severe stresses on local water resources.

In response to this issue, operators have developed several ways to alleviate some of the stresses brought on by the extensive water use such as alternative sourcing and reuse technologies. Companies are driven to exercise these options and decrease their fresh water usage for hydraulic fracturing processes for multiple reasons, including changes in regulation, to gain support of local communities, and to increase efficiencies of operations. Whatever the motivation may be, there are a variety of options companies

have at their disposal to reduce fresh water demands—dependent on specific formation characteristics, the qualities and quantities of available water, among others.

The Eagle Ford shale is one of the most rapidly growing shale plays in the country. However, this formation is located in a fairly arid part of the country. Because of meager average rainfall totals, water availability to meet demand is an issue of great concern. Due to nearly exponential increases in shale production, stresses on local water supplies have dramatically increased as well.

The objectives of this thesis are as follows: 1) to establish the enormous resource that has become available; while still recognizing the environmental impacts associated with development processes, focusing primarily on water requirements and associated wastewater production; 2) to break down current water demand for shale development, as well as wastewater management practices in the Eagle Ford, with a brief comparison to other shale plays across the country; 3) to obtain an understanding of operator motivation—what factors affect wastewater management strategies; and 4) to analyze techniques operators presently have at their disposal to reduce fresh water demands, specifically through the use of brackish waters and recycling/reuse efforts, and finally to quantify these efforts to evaluate potential fresh water savings.

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1. INTRODUCTION AND OBJECTIVES

Hydraulic fracturing technology has unlocked a tremendous resource across the United States and around the world. Shale formations—the source rock for conventional oil and natural gas reservoirs—house an enormous supply of natural gas and oil resources. With the use of this newly repurposed technology, coupled with horizontal drilling, this asset can now be harnessed in an economical fashion.

However, hydraulic fracturing processes have come with a myriad of potential environmental effects, including a substantial demand for water. Shale development through hydraulic fracturing can require anywhere between two and four million gallons of water per well, on average. This considerable quantity of water is also needed in its entirety within a few days, during the actual stimulation process. Usage of such large quantities of water, within very short periods of time, can result in severe stresses on water resources, such as the depletion of aquifers, damage to river ecosystems, and other potentially adverse consequences.

In response to this issue, operators have developed a number of techniques, including alternative sourcing and recycling technologies, to alleviate some of the stresses brought on by the extensive water use and subsequent fluid management requirements, while still supplying adequate water resources for development. Companies are driven to exercise these options and decrease their fresh water usage for hydraulic fracturing processes for multiple reasons, including changes in regulatory frameworks, to gain the trust and support of local communities, and to increase efficiencies of operations. Whatever the motivation may be, there are a variety of options companies have at their disposal to reduce fresh water demands for shale development—dependent on specific formation characteristics, qualities and quantities of available water, among numerous other factors.

The Eagle Ford shale, located in south Texas, is one of the most rapidly growing shale plays in the country. With significant oil supplies accompanying the natural gas resources, the economic attractiveness of this play with current resource prices has spurred sudden interest and development within this region. However, this formation is also located in a fairly arid portion of the country. Because of the meager average rainfall totals found in this region, water availability to meet current and future demand is an issue of great concern. Due to nearly exponential increases in shale production within the Eagle Ford, stresses on local water supplies have increased dramatically with the presence of the oil and gas industry.

For this reason, I have chosen the Eagle Ford as a case study to examine the potential for different fresh water reduction strategies for hydraulic fracturing, specifically by looking at current and future wastewater management programs of operators within the play. The options will be focused on the use of brackish water in fracture fluids and the implementation of treatment technologies to recycle wastewater for reuse in subsequent hydraulic fracture stimulations.

The objectives of this thesis are as follows: 1) to establish the enormous natural resource base that has become available—shale; while still recognizing the environmental impacts associated with development processes, specifically focusing on water issues (water requirements and associated wastewater production); 2) to break down current water demand for shale development, as well as wastewater management practices (disposal versus treatment), in the Eagle Ford shale specifically, with a brief comparison to other shale plays across the country; 3) to obtain an understanding of operator motivation—what factors affect wastewater management strategies; and finally 4) to analyze techniques operators in the Eagle Ford can implement to reduce fresh water demands, specifically through the use of brackish water and recycling efforts, and to quantify these efforts to evaluate potential fresh water savings.

2. BACKGROUND

To fully grasp the issues addressed throughout this thesis, a certain level of background understanding is necessary. This section seeks to provide the reader with an adequate base of knowledge with which to understand and apply the following information.

Shale formations are very fine-grained organic rock deposits with extremely low permeabilities. They have been known to contain oil and natural gas resources for decades, as they are the source rock for conventional oil and gas reservoirs. However, due to both technological and economic constraints, only within the past three decades have these formations been actively pursued for their natural resource content.

In the early 1980s, George Mitchell, often referred to as the "father of shale gas", began working in the Barnett shale of North Texas, attempting to apply hydraulic fracturing technologies to extract natural gas from shale formations. After over a decade of diligence and experimentation, Mitchell successfully fractured a vertical well in an economical fashion.[1] This sparked the revolution of domestic, on-shore natural gas production from shales, subsequently spurring the use of these same production practices for oil extraction from shales as well.

2.1 United States Shale Resource Outlook

Since Mitchell's tremendous success in the Barnett, shale formations have emerged across the country—even around the world—as economically viable oil and

[1] Yergin, Daniel. Stepping on the Gas. *Wall Street Journal.* 04/02/11. Accessed on 02/16/13, http://online.wsj.com/article/SB10001424052748703712504576232582990089002.html.

natural gas deposits. Figure 1[2] is a map of the shale plays within the continental United States (as of 2011). Estimates for both oil and natural gas residing in these shale formations are substantial.

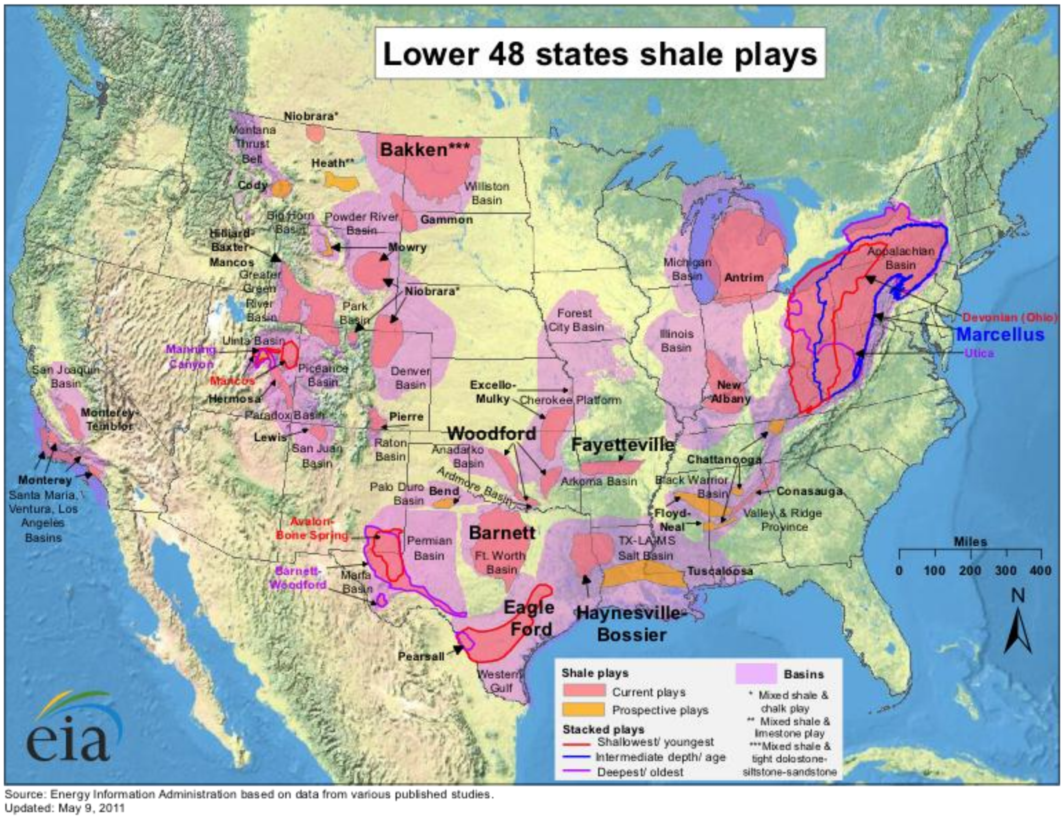

Figure 1: Map of Shale Plays in the Continental United States

As of early 2012, the U.S. Energy Information Administration (EIA) declared a resource estimate for shale gas at 482 trillion cubic feet (Tcf) and a shale oil resource estimate of 33.2 billion barrels.[3] To put this current resource assessment into perspective,

[2] Lower 48 states shale plays. *U.S. Energy Information Administration.* 05/09/11. Accessed on 02/16/13, http://www.eia.gov/oil_gas/rpd/shale_gas.pdf.

[3] Annual Energy Outlook 2012 with Projections to 2035. *U.S. Energy Information Administration/U.S. Department of Energy.* June 2012. Accessed on 08/29/12, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

in 2011, the US consumed 24.4 Tcf of natural gas.[4] Applying that rate of consumption to the current resource estimate, natural gas from shale formations alone could supply US demand for roughly 20 years. Additionally, in 2011, the US consumed 6.9 billion barrels of refined petroleum products and biofuels[5]; thus, the shale oil resource base could potentially satisfy the country's petroleum demand for nearly five years, at current rates of consumption.

To accompany these promising resource estimates, production of natural gas and oil with the use of these game-changing technologies—hydraulic fracturing and horizontal drilling—has grown nearly exponentially over the past decade. Shale gas production increased from 1.3 Tcf in 2007 to 5.3 Tcf in 2010[6], making up approximately 25 percent of total natural gas production (in 2010). Shale oil production has increased more than fivefold, from approximately 39 million barrels in 2007 to approximately 217 million barrels in 2011.[7] These production rates are only expected to increase in the future; shale gas production is expected to double by 2035, accounting for 49 percent of total natural gas production. Shale oil production is also projected to double, peaking in

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[4] How much natural gas is consumed (used) in the U.S.? *U.S. Energy Information Administration.* 03/01/12. Accessed on 11/13/12, http:www.eia.gov/tools/faqs/faq.cfm?id=50&t=8.

[5] How much oil does the United States consume per year? *U.S. Energy Information Administration.* 06/19/12. Accessed on 11/13/12, http://www.eia.gov/tools/faqs/faq.cfm?id=33&t=6.

[6] Shale Gas Production, *Energy Information Administration.* Released 08/02/2012. Accessed on 11/05/12, http://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm.

[7] Oil and Gas: Information on Shale Resources, Development, and Environmental and Public Health Risks. *United States Government Accountability Office.* September 2012, http://www.gao.gov/assets/650/647791.pdf.

2027 at 1.3 million barrels per day (bbl/d) (approximately 475 million barrels annually), decreasing slightly to 1.2 million bbl/d by 2035 (less than 440 million barrels annually).[8]

The application of hydraulic fracturing and horizontal drilling technologies to shale and tight (very low permeability) formations has revolutionized the resource outlook in the United States—both for oil and natural gas. These processes have opened up an enormous resource base, conceivably resulting in a decrease of US dependence on foreign fossil fuel supplies, an increase in domestic economic development, as well as a transformation within not only the energy generation industry but other industries, such as the chemical industry, as well; "The benefits of shale could allow US industry to lower raw materials and energy costs by $11.6 billion and create approximately one million more jobs by 2025."[9] Furthermore, with natural gas now rivaling coal for electricity production due to increased supply (coal, 34 percent; natural gas, 32 percent in May 2012), greenhouse gas emissions are also being reduced.[10] This large resource base coupled with the tremendous production success demonstrated above support the enormous potential shale gas and shale oil have for changing not only the resource outlook for the US but the general economy and associated externalities of progress as well, spurring conversations about greater energy security and even energy independence.

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[8] Annual Energy Outlook 2012 with Projections to 2035. *U.S. Energy Information Administration.* June 2012, www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
[9] Manning, Robert A. Shale Revolution Shakes the World. *Ideas Laboratory.* 10/22/12. Accessed on 04/11/13, http://www.ideaslaboratory.com/2012/10/22/robert-manning-shale-revolution-shakes-the-world/.
[10] Id.

2.2 Key Technologies—Hydraulic Fracturing and Horizontal Drilling

This dramatic change for the US resource outlook would not be possible without the application of two previously used technologies—hydraulic fracturing and horizontal drilling—which have made the production of oil and natural gas from shale formations both technically possible and economical.

Horizontal drilling is a form of drilling that has dramatically altered shale development. This process first involves vertically drilling thousands of feet below the surface, then gradually shifting the drill bit horizontally and drilling up to a mile or more laterally—directly into the target formation. Horizontal drilling has many beneficial qualities: 1) It allows for increased contact with the producing formation, yielding increased resource production; to exemplify the extent of this increased contact, "six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells."[11]; 2) With multiple wells on each pad, fewer well pads need to be constructed, and with greater formation contact, fewer wells need to be drilled overall—minimizing habitat disturbance; and 3) It offers flexibility in well pad location, allowing for development under urban or environmentally sensitive areas, among other difficult or challenging environments, with minimal surface disturbance. Additionally, no new environmental concerns have surfaced from present horizontal drilling practices.[12]

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[11] Modern Shale Gas Development in the United States: A Primer. *U.S. Department of Energy: National Energy Technology Laboratory.* April 2009. Accessed on 03/11/13, http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.
[12] Id.

Hydraulic fracturing, the other key to harnessing shale resources, involves the injection of vast amounts of fracturing fluid—a mixture of roughly 90 percent water, 10 percent proppant (typically sand), and less than one percent chemicals, such as corrosion inhibitors, biocides, and friction reducers—deep into the subsurface, targeting a shale or tight formation. The fluid is injected at very high pressures in order to induce fractures within the formation, which increases permeability, allowing the oil or natural gas to flow freely to the well. However, this process is not without issues—multiple potential environmental impacts arise throughout the lifecycle of the hydraulic fracturing process.

2.3 Environmental Impacts of Shale Development

Despite the numerous positive developments that have come with the realization of this new resource base, a number of both proven and potential environmental implications have arisen as well. These impacts range from air emissions, noise, road traffic, and groundwater contamination to landscape alterations and induced seismic activity (earthquakes). Additionally, the availability of and effect on water supplies required for the hydraulic fracturing process are of particular concern, as well as utmost importance. So, for the sake of this thesis, the focus will only be on the water-related environmental impacts.

2.3.1 Fracturing Fluids

The combination of water, proppant, and chemicals is what has made hydraulic fracturing possible; creating the perfect fracture fluid "cocktail" is key to a successful hydraulic fracture stimulation. There is no one-size-fits-all mixture. Each shale play has its own unique chemical makeup and properties, requiring different combinations and qualities of ingredients within the fracture fluid to yield the desired results, for example, a specific fracture configuration.

The proppant—most commonly sand—is used to prop open the fractures, allowing the oil or natural gas to flow. Without proppants, the fractures would quickly close due to the enormous overburden pressures felt within these target shale formations, which generally reside thousands of feet below the surface. Proppants usually make up roughly eight to ten percent of the fracture fluid.

Additionally, a chemical cocktail is created, a mixture of numerous chemicals—each with their own unique purpose. The most common chemicals include friction reducers, biocides, oxygen scavengers, and/or scale inhibitors[13] to insure the fracture process proceeds smoothly. Chemical concentrations typically range between 0.01 to less than one percent. As for the fate of these chemicals once in the subsurface, "The majority of the chemical additives are thought to be adsorbed or absorbed in the formation and very little are recovered."[14] Figure 2[15] is an example of a fracture fluid makeup, specifically for the Fayetteville shale in Arkansas.

[13] King, George E. Thirty Years of Gas Shale Fracturing: What Have We Learned? *Society of Petroleum Engineers.* SPE 133456. 2010.
[14] Id.
[15] Exhibit 35. Modern Shale Gas Development in the United States: A Primer. *U.S. Department of Energy: National Energy Technology Laboratory.* April 2009. Accessed on 03/11/13, http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

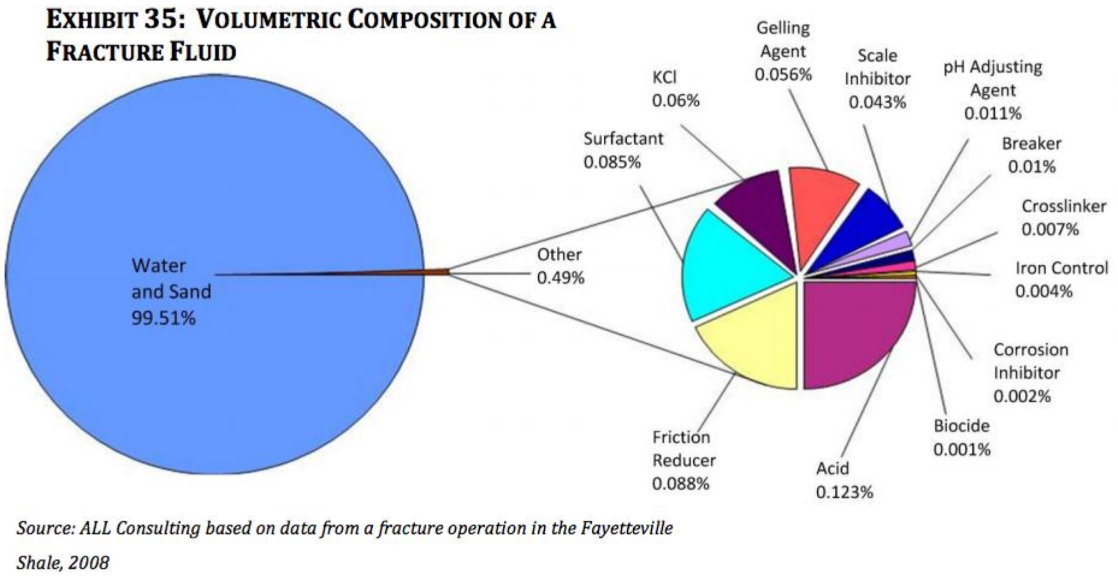

Figure 2: Representation of a Potential Fracture Fluid Configuration

Slickwater fracturing has become relatively standard between shale plays[16]; this process uses primarily fresh water for the fluid, a development that "lowered fracturing cost, penetrated and enlarged natural fractures and significantly increased the undamaged fracture contact area with many shale formations"[17]. In addition to slickwater, gel- or foam-based fracture fluids are alternative options; these bases have higher viscosities, allowing for proppant transport further within the formation. "The choices depend on

[16] King, George E. Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Oil and Gas Wells. *Society of Petroleum Engineers.* SPE 152596. 2012.

[17] King, George E. Thirty Years of Gas Shale Fracturing: What Have We Learned? *Society of Petroleum Engineers.* SPE 133456. 2010.

increasing shale contact area, meeting proppant placement needs and achieving production results."[18]

Both slickwater and alternative fracturing fluids can have substantial water requirements—anywhere between two and four million gallons of water or more per well. Although water withdrawals for hydraulic fracturing may only amount to a fraction of the withdrawals of surrounding users, such as municipalities or agriculture (as seen in Texas, with oil and gas industry water use accounting for less than two percent of total water use across the entire state in 2010[19]), depending on the climate and available water resources near a shale formation, the considerable water requirements can create substantial stresses on water systems. Depending on the time of year the water is removed, among other factors, withdrawals for hydraulic fracturing could potentially alter stream or river environments, deplete surrounding aquifers, or damage these resources in other potentially irreparable ways. These substantial water requirements can also create tensions in local areas within communities and local or governmental organizations, as well as between competing water users, such as municipalities, agriculture, and industry.

In addition to the environmental impact the water requirements for hydraulic fracturing may place on surrounding water resources described above, the environmental impact of the fracture fluids themselves must be acknowledged. These risks come into play primarily at the surface—through transportation, handling, and storage. "Although

[18] King, George E. Thirty Years of Gas Shale Fracturing: What Have We Learned? *Society of Petroleum Engineers.* SPE 133456. 2010.

[19] 2012: Water For Texas, State Water Plan. *Texas Water Development Board.* January 2012. Accessed on 03/19/13, http://www.twdb.state.tx.us/publications/state_water_plan/2012/2012_SWP.pdf.

the risk is low, the potential exists for unplanned releases that could have series effects on human health and the environment."[20] The chemicals pose a threat to the land and surrounding resources if improperly handled or spilled. If a spill were to occur prior to the mixing and subsequent dilution of these chemicals into the fracture fluid, the contamination potential could be even more harmful; though both instances of mishandling could potentially be damaging.

2.3.2 FLOWBACK AND PRODUCED WATERS

Following the injection process, a portion of the originally injected fracture fluid returns to the surface as flowback water, along with produced water, which is water previously residing in the formation. Flowback water can contain a range of chemicals from the original fracture fluid among other constituents derived from the formation itself, all of which could potentially be very damaging to the environment if improperly released. Produced water can also contain a range of constituents, including naturally occurring radioactive materials (NORM) and high salt concentrations, ranging anywhere between 5,000 parts per million (ppm) total dissolved solids (TDS) to greater than 400,000 ppm[21]. If spilled or released, this produced water also has potential for contamination.

The amount of flowback and produced water production varies between shale plays—even between wells within a play. The amount of flowback water that comes back

[20] Modern Shale Gas Development in the United States: A Primer. *U.S. Department of Energy: National Energy Technology Laboratory.* April 2009. Accessed on 03/11/13, http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.
[21] Id.

to the surface can range on average anywhere between 30 and 70 percent of the originally injected volume[22], sometimes even less (as will be seen later). Additionally, the quality of this water varies depending on the characteristics of the shale formation, the water originally housed in the formation, and among other factors, time—both as in time residing in the formation and time of production at the surface, i.e. a week after stimulation versus two months.

Operators must find a way to properly treat and/or dispose of these waters in a manner that does not contaminate surrounding water sources, including groundwater or other natural resources. The primary avenues available to operators include: 1) disposal through injection in a Class II well, which is an oil and gas-related injection well classified by the U.S. Environmental Protection Agency (Fluids associated with oil and natural gas production—typically brines—are injected into this type of well for either enhanced recovery or final disposal.[23]); 2) treatment (either on- or offsite) to the degree that it can be reused in subsequent hydraulic fracture stimulations or legally released into surrounding waterways; or 3) land application. The availability of these treatment options depends greatly on location. For example, in Texas, the geology is highly conducive for deep underground injection through a Class II well, making this option affordable and feasible to operators across many actively developing parts of the state (injection within these wells being monitored and regulated by the Railroad Commission of Texas, RRC).

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[22] Modern Shale Gas Development in the United States: A Primer. *U.S. Department of Energy: National Energy Technology Laboratory.* April 2009. Accessed on 03/11/13, http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

[23] Class II Wells – Oil and Gas Related Injection Wells (Class II). U.S. Environmental Protection Agency. 05/09/12. Accessed on 03/01/13, http://water.epa.gov/type/groundwater/uic/class2/.

On the other hand, in Pennsylvania, the geology does not allow for Class II disposal, making treatment essentially a requirement unless the operator is willing to truck the wastewater to the nearest disposal well—which in the Pennsylvania case is out of state (Ohio). Wastewater management strategies that are currently being employed in various plays can be found in Table 1[24].

Shale Basin	Water Management Strategy
Barnett Shale	Class II Injection Wells
	Recycling
Fayetteville Shale	Class II Injection Wells
	Recycling
Haynesville Shale	Class II Injection Wells
Marcellus Shale	Class II Injection Wells (in Ohio)
	Treatment and Discharge
	Recycling
Woodford Shale	Class II Injection Wells
	Land Application
	Recycling
Antrim Shale	Class II Injection Wells
New Albany Shale	Class II Injection Wells

Table 1: Water Management Strategies Utilized by Shale Play

With these different strategies, it is important to note the benefits and drawbacks of each option. Generally speaking, for disposal in a Class II well, the cost to the operator of disposal itself is generally quite cheap; however, once injected deep into the subsurface, this water is permanently removed from the water cycle, resulting in a

[24] Data obtained from Exhibit 39, Modern Shale Gas Development in the United States: A Primer. *U.S. Department of Energy: National Energy Technology Laboratory.* April 2009. Accessed on 03/11/13, http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

consumptive use—never to be used again—which may result in a greater cost to the public in the future. Treatment of wastewater can be costly to operators, as well as energy intensive (in order to run the technologies), which depending on the power source may result in associated emissions; however, it allows this water to be recycled and used again, either to supply subsequent hydraulic fracture stimulations or to be released into surrounding water bodies, returning to the water cycle. Finally, for land application, a disposal option that is utilized primarily in Oklahoma, operators must comply with regulatory requirements and treat the wastewater to a certain degree before it is deemed acceptable to apply directly to the surface. However, with improper or insufficient treatment, contamination can obviously occur through this management method.

The remainder of this thesis will focus on recycling treatment technologies as a wastewater management method, as well as look at current disposal methods in the Eagle Ford shale specifically, comparing the available options in this region.

2.4 Eagle Ford Shale, Texas

The Eagle Ford shale—the case study for this thesis—is one of the fastest growing shale plays in the country, spanning from the Mexican border northeast across Texas. The play's high oil and wet gas/condensate content has made it very economically attractive to develop, especially compared to other plays consisting solely of natural gas—which in today's market is trading at historically low prices.

2.4.1 CHARACTERISTICS OF THE EAGLE FORD SHALE

The Eagle Ford shale was deposited in the Cretaceous period, running roughly 50 miles wide and 400 miles long, with an average thickness of 250 feet; its depth ranges from 4,000 to 12,000 feet.[25] Figure 3[26] is a map, showing the three windows of the Eagle Ford—oil, wet gas/condensate, and natural gas. Figure 4[27] shows where the majority of the activity is currently occurring, with the dots corresponding to completed and permitted wells as of March 7, 2013.

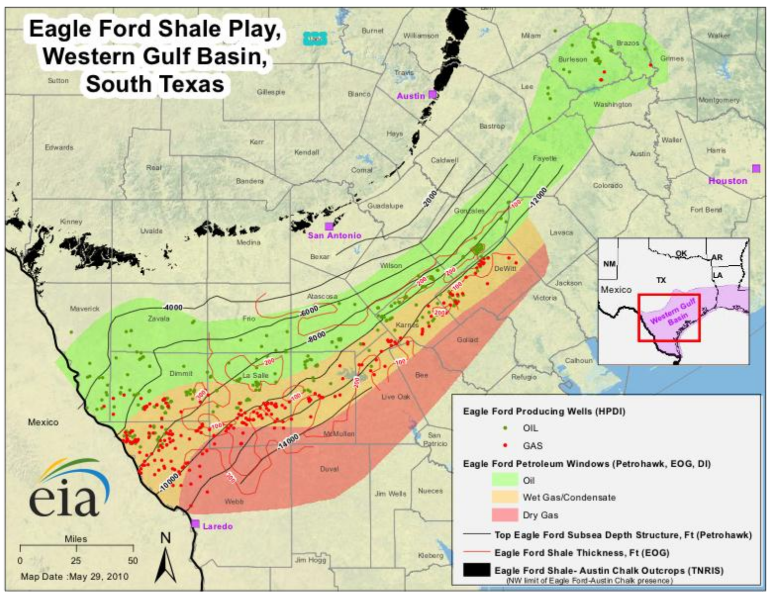

Figure 3: Map of the Eagle Ford, Displaying Varying Resource Windows

[25] Eagle Ford Information. *Railroad Commission of Texas.* Last updated 03/08/13. Accessed on 03/11/13, http://www.rrc.state.tx.us/eagleford/index.php.

[26] Eagle Ford Shale Play, Western Gulf Basin, South Texas. *U.S. Energy Information Administration.* 05/29/10. Accessed on 03/11/13, http://www.eia.gov/oil_gas/rpd/shaleusa9.pdf.

[27] Wells Completed and Permitted in the Eagle Ford Shale Play. *Railroad Commission of Texas.* 03/07/13. Accessed on 03/11/13, http://www.rrc.state.tx.us/eagleford/images/EagleFordShalePlay201303-large.jpg.

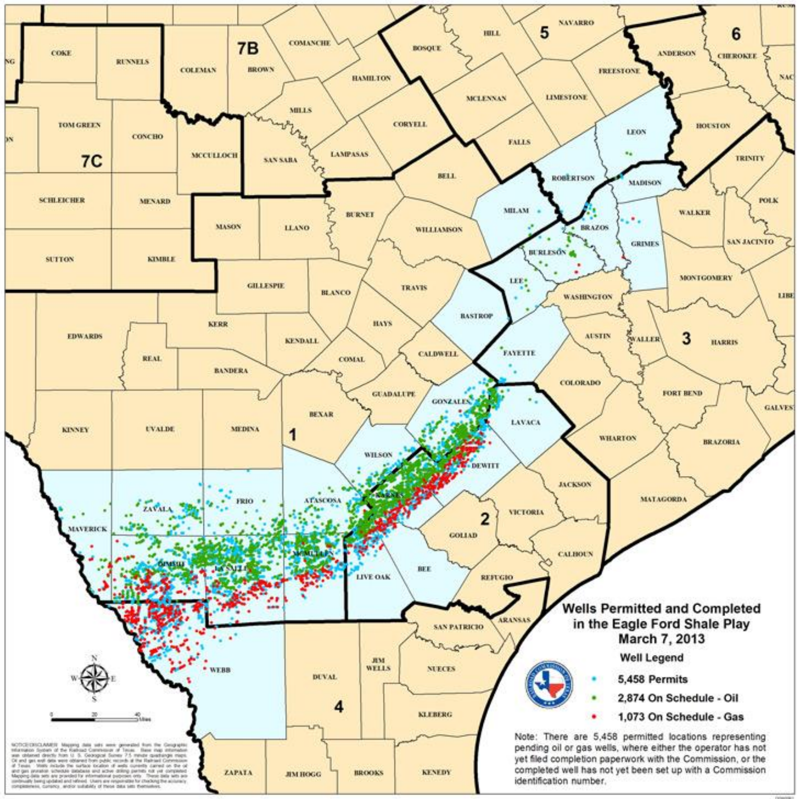

Figure 4: Completed and Permitted Wells in the Eagle Ford Shale

Production in the Eagle Ford began when the first well was drilled in 2008 by Petrohawk. Since then, development has increased nearly exponentially, beginning with 26 drilling permits in 2008 and multiplying to over 4,000 by the end of 2012.[28] Production of natural gas, oil, and condensates from this shale has followed the same trend. Natural gas production increased from a mere eight million cubic feet (MMcf) in 2008 to 950 MMcf in 2012[29]; oil production increased from 358 bbl/d in 2008 to nearly

[28] Texas Eagle Ford Shale Drilling Permits Issued 2008 through 2012. *Railroad Commission of Texas.* 02/21/13. Accessed on 03/11/13, http://www.rrc.state.tx.us/eagleford/EagleFordDrillingPermitsIssued.pdf.
[29] Texas Eagle Ford Shale Gas Well Gas Production 2008 through 2012. *Railroad Commission of Texas.* 02/21/13. Accessed on 03/11/13, http://www.rrc.state.tx.us/eagleford/EagleFordGWGProduction.pdf.

340,000 bbl/d by the end of 2012[30]; and condensate production increased from 1,423 bbl/day to 71,748 bbl/day from 2008 through 2012[31]. Figure 5[32] is a chart visually depicting the oil and natural gas seemingly exponential production trends throughout the history of development within this play.

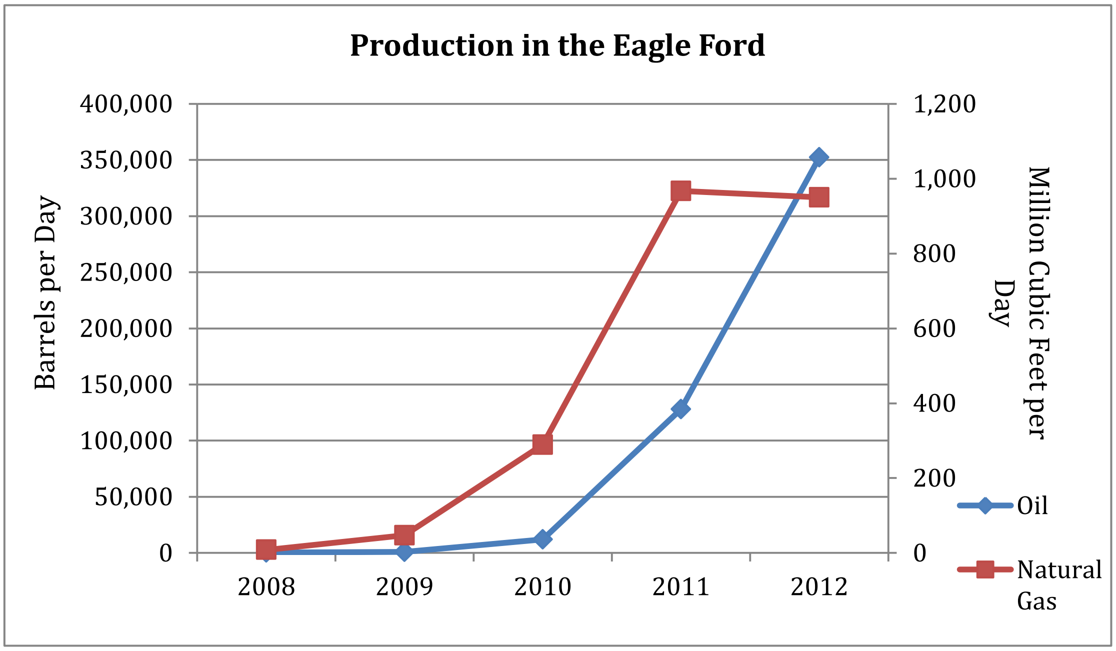

Figure 5: Production of Oil and Natural Gas in the Eagle Ford Shale

2.4.2 Water Availability in the Eagle Ford Shale Region

With such a rapidly growing industry in this area, many concerns have been raised about potential negative effects on surrounding communities—one primary concern has been water availability. Water has recently and swiftly moved to the

[30] Texas Eagle Ford Shale Oil Production 2008 through 2012. *Railroad Commission of Texas.* 02/21/13. Accessed on 03/11/13, www.rrc.state.tx.us/eagleford/EagleFordOilProduction.pdf.

[31] Texas Eagle Ford Shale Condensate Production 2009 through 2012. *Railroad Commission of Texas.* 02/21/13. Accessed on 03/11/13, http://www.rrc.state.tx.us/eagleford/EagleFordCondensateProduction.pdf.

[32] Data obtained from Eagle Ford Statistics. *Railroad Commission of Texas.* 02/21/13. Accessed on 03/11/13, http://www.rrc.state.tx.us/eagleford/EagleFordGWGProduction.pdf; http://www.rrc.state.tx.us/eagleford/EagleFordOilProduction.pdf.

forefront of pressing issues across the state of Texas, as 2011 marked the most severe one-year drought ever recorded. These very dry trends continue with most recent data showing 90 percent of Texas experiencing abnormally dry conditions and 22 percent in extreme or exceptional drought.[33] Due to this drought, water awareness and concern has shifted to the oil and gas industry as well.

The rapidly developing portion of the Eagle Ford shale (as can be seen in Figure 4 above) is located in a fairly arid portion of Texas. As demonstrated in the map below, Figure 6[34], average rainfall in this region is roughly 20 to 30 inches of rain per year, with an emphasis on the lower side. These minimal rainfall totals have raised concerns regarding the quantity of water required for shale gas development activities.

This is a concern somewhat unique to the Eagle Ford shale, as many other shales are located in wetter climates or areas with greater occurrences of surface water (which are generally considered renewable sources of water). For example, "the average annual precipitation that falls in the Marcellus shale area is approximately 43 inches and is evenly distributed over the course of the year"; this is roughly ten inches more per year than the average precipitation totals for the continental US.[35] As a result, water availability necessary for the shale development industry in this area of the country is of minimal concern.

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[33] Tresaugue, Matthew. Texas drought could rival state's worst dry years. *Houston Chronicle.* 02/05/13. Accessed on 03/12/13, http://www.chron.com/news/article/Texas-drought-could-rival-state-s-worst-dry-years-4253137.php.

[34] Accessed in October 2011, www.tnris.state.tx.us.

[35] Arthur, Daniel, Brian Bohm, and Mark Layne. Hydraulic Fracturing Considerations for Natural Gas Wells in the Marcellus Shale. *ALL Consulting.* Presented at the Groundwater Protection Council, 2008 Annual Forum. September 21-24, 2008. Accessed on 03/25/13, http://www.dec.ny.gov/docs/materials_minerals_pdf/GWPCMarcellus.pdf.

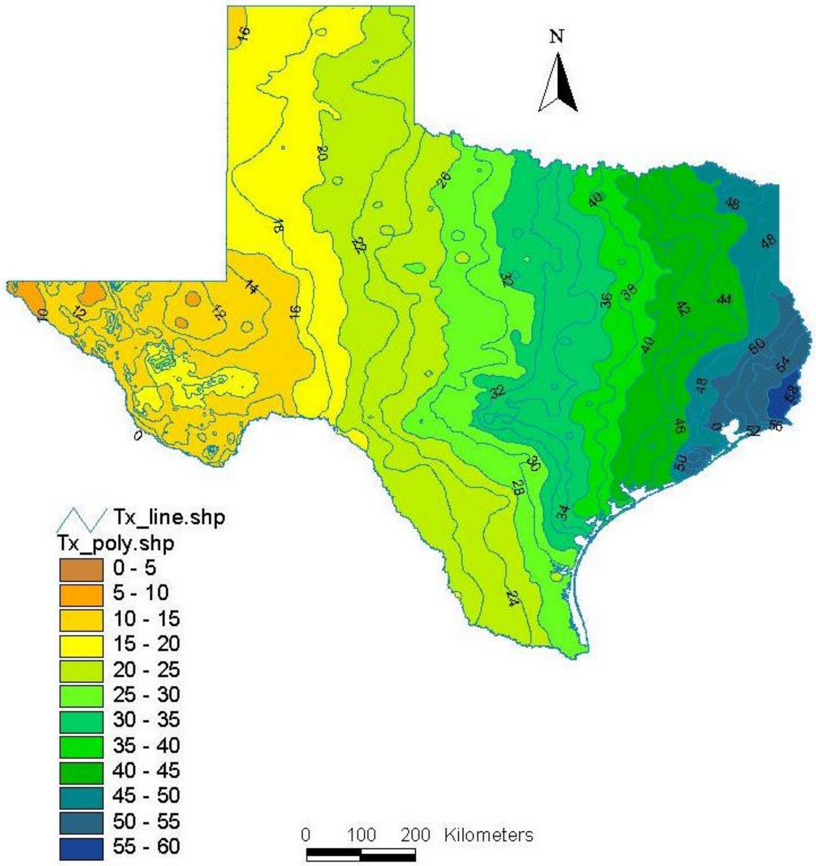

Figure 6: Distribution of Mean Annual Precipitation in Texas (in inches)

On the other hand, in South Texas, due to the relatively dry conditions, surface water is minimal, forcing users including the oil and gas industry to rely primarily on groundwater for their water resources. There are two major sources of groundwater responsible for providing water resources for all of the sectors in this region; they are the Carrizo-Wilcox aquifer and the Gulf Coast aquifer.

In the Eagle Ford shale, municipalities and agriculture are the primary competitors for fresh water supplies. As can be seen in Figure 7[36], hydraulic fracturing processes (included within the mining category) only contribute to a very small fraction of total water consumption, making up less than four percent of the total (as mining is also made up of coal extraction, among other practices). Region L, the South Central Texas Regional Water Planning Area, is shown here; its boundaries span a significant portion of the Eagle Ford, specifically where much of the development is currently progressing and therefore where much of the water demand/use occurs.

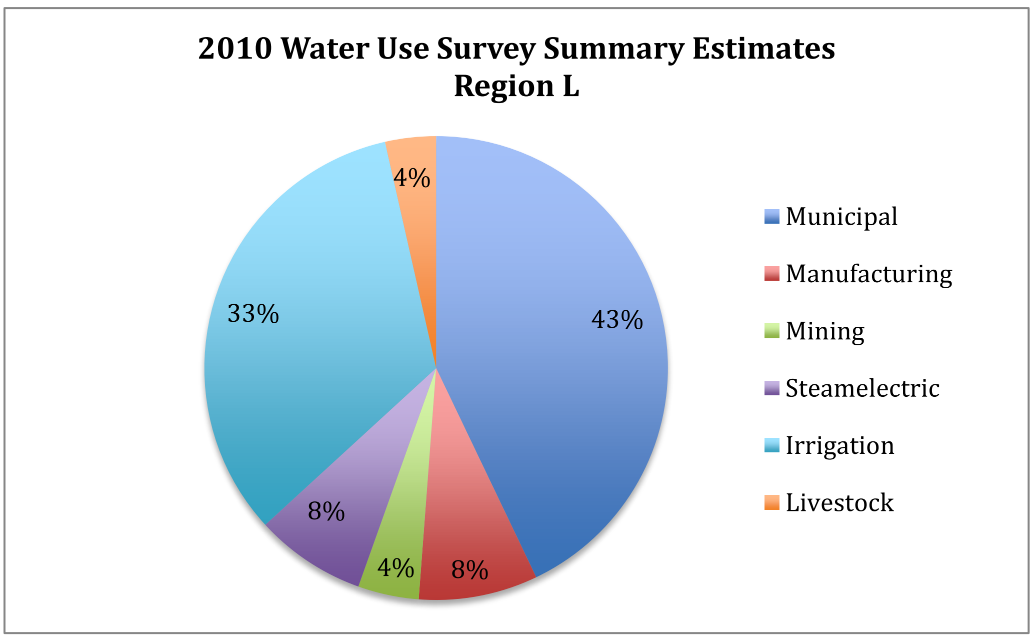

Figure 7: Water Use in Region L, South Central Texas, 2010

Even though shale development demands only a fraction of the water that other consumers utilize, specifically municipalities and agriculture, it is still a significant

[36] Data obtained from 2010 Water Use Survey Summary Estimates – Regional & State Totals. *Texas Water Development Board.* Accessed on 03/12/13, http://www.twdb.state.tx.us/waterplanning/waterusesurvey/estimates/2010/index.asp.

amount of water, and due to the fairly arid conditions of this region, water is a highly valued commodity. As a result, water use by the oil and gas industry must be given due consideration—the inspiration for the use of the Eagle Ford as a case study to examine potential fresh water reduction strategies and technologies for hydraulic fracturing .

3. METHODS

A literature review was executed to assess the current hydraulic fracturing environment in the Eagle Ford shale, e.g. current water use, development, production, etc., as well as any available projections for the future. Existing recycling technologies and their respective features, as well as potential, were likewise researched through literature reviews. Sources for this information included, but were not limited to, peer-reviewed journals, grey literature, and reports from federal, state, and private companies.

A number of interviews with specialists from large operators in the Eagle Ford shale were conducted to gage current water management activities and any future plans for recycling or reuse. Four companies were contacted: ConocoPhillips, Pioneer Natural Resources, Chesapeake, and Halliburton. Large operators were selected, as their operations have the largest effect on the region, including the water resources. Therefore, they are able to offer a representation of general trends across the play as a whole. Halliburton was included to obtain a service-provider perspective; although it is acknowledged that water management decisions are generally made by the operator. The following questions were asked in the interviews:

1. What is your current flowback/produced water management strategy?
2. Do you/have you employed any reuse or recycling efforts? If so, how much?
3. Have you looked into implementing any reuse/recycling efforts in the past or for the future? What has impacted your decision?

4. What is your motivation for implementing (or not) recycling/reuse technologies and practices?
5. Do you use brackish water in your fracture fluids?

The responses were then compiled to estimate a general trend for both current and future recycling/reuse efforts in the Eagle Ford, as well as potential reasons behind the implementation or lack-thereof.

A high-level economic analysis was also performed to determine the cost-effectiveness of different water management options—disposal through injection into the subsurface or treatment and reuse. Utilizing all of this information, an overall analysis was accomplished and conclusions were drawn as to the potential for future implementation of recycling/reuse technologies in the Eagle Ford shale, as well as reasons that may encourage or inhibit these efforts.

4. RESULTS

4.1 Water Use for Hydraulic Fracturing

4.1.1 OVERVIEW

Hydraulic fracturing processes can require on average anywhere between two and four million gallons of water per well, sometimes more. As discussed in Chapter 2, water is the primary component of fracture fluids. This water can be sourced from surface water bodies, municipal supplies, groundwater, wastewater sources, or recycled from other sources including previous hydraulic fracturing operations.[37] The amount of water required varies due to many factors, including the chemical makeup of the shale formation and the desired fracture complex. Table 2[38] shows approximate water demands for various shale plays, as determined by Chesapeake Energy's operations. Notably, there is considerable variation in water requirements between shale plays across the country—3.3 million gallons per well in the Niobrara formation, which is found in the west primarily throughout parts of Colorado and Wyoming, to 6.1 million gallons per well in the Eagle Ford of South Texas.

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[37] Water Management Associated with Hydraulic Fracturing: API Guidance Document HF2. *American Petroleum Institute.* First Ed. June 2010.

[38] Mathis, Mike. Shale Natural Gas – Water Use Management: ICWP Annual Meeting – St. Louis, MO. *Chesapeake Energy.* October 11-14, 2011. Accessed on 03/13/13, http://www.icwp.org/cms/conferences/Mathis14Oct2011.pdf.

Shale Play	Water used for Drilling	Water used for Fracturing	Total (gallons)
Barnett	250,000	3,800,000	**~ 4.0 million**
Eagle Ford	*125,000*	*6,000,000*	***~ 6.1 million***
Fayetteville	65,000	4,900,000	**~ 4.9 million**
Haynesville	600,000	5,000,000	**~ 5.6 million**
Marcellus	85,000	5,500,000	**~ 5.6 million**
Niobrara	300,000	3,000,000	**~ 3.3 million**

Table 2: Estimated Water Required for Drilling and Fracturing Wells in Select Shale Gas Plays, Chesapeake Energy

Due to the nature of water use for hydraulic fracturing, these large water quantities are needed within a very short period of time—on the order of days. Depending on the water source and time of year, "withdrawals…could affect fish and other aquatic life, fishing and other recreational activities, municipal water supplies, and other industries such as power plants".[39]

However, these large water requirements per well do not necessarily have to be fresh "potable" water (water safe for human consumption). Hydraulic fracturing processes were originally—and commonly now—performed with fresh water, which simplified the fracture fluid composition. The use instead, of higher salinity base fluids—brackish waters, defined here as water with greater than 1,000 milligrams per liter (mg/L) total dissolved solids (TDS)—has been experimented with and is currently being used in many plays. This option is of particular impact in more arid or dry areas like the Eagle

[39] Modern Shale Gas Development in the United States: A Primer. *U.S. Department of Energy: National Energy Technology Laboratory.* April 2009. Accessed on 03/11/13, http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

Ford, where available fresh water supplies may be limited, making hydraulic fracturing possible where it may not have been previously feasible.

Utilizing higher salinity fluids (which are considered non-potable) eliminates much of the competition with municipalities and many other sectors such as agriculture, which require fresh water for irrigation (though not eliminating it entirely, as a few municipalities located in areas of low freshwater supply may be looking into brackish water for desalination, though the degree of water quality would be different with municipalities wanting generally less than 3,000 mg/L TDS). Use of non-potable sources also diminishes public concern over fresh water supplies. "In some cases, operators are using saline waters with up to 30,000 parts per million [total dissolved solids] as a water source for hydraulic fracturing where fresh water availability may be uncertain or limited."[40]

Brackish water is commonly found throughout Texas and the United States. Figure 9[41] is a map showing the distribution of brackish groundwater across the state of Texas, while Table 3[42] following shows brackish water supply estimates at the Texas-state, Eagle Ford-specific region, and Eagle Ford-specific aquifer levels. As can be seen, total supply figures are substantial. There are over 2.7 billion acre-feet (~880 trillion gallons) of brackish water supplies across the state of Texas—over 415 million acre-feet of which reside in Region L, an area (as previously discussed) that encompasses much of

[40] Water Management Associated with Hydraulic Fracturing: API Guidance Document HF2. *American Petroleum Institute.* First Ed. June 2010.
[41] Kalaswad, Sanjeev, Brent Christian, and Rima Petrossian. Brackish Groundwater in Texas. *Texas Water Development Board.* Accessed on 03/25/13, http://www.twdb.state.tx.us/publications/reports/numbered_reports/doc/r363/b2.pdf.
[42] Id.

the rapidly developing portion of the Eagle Ford shale. As will be seen in the next section, water requirements in the Eagle Ford could more than be met by these brackish water resources.

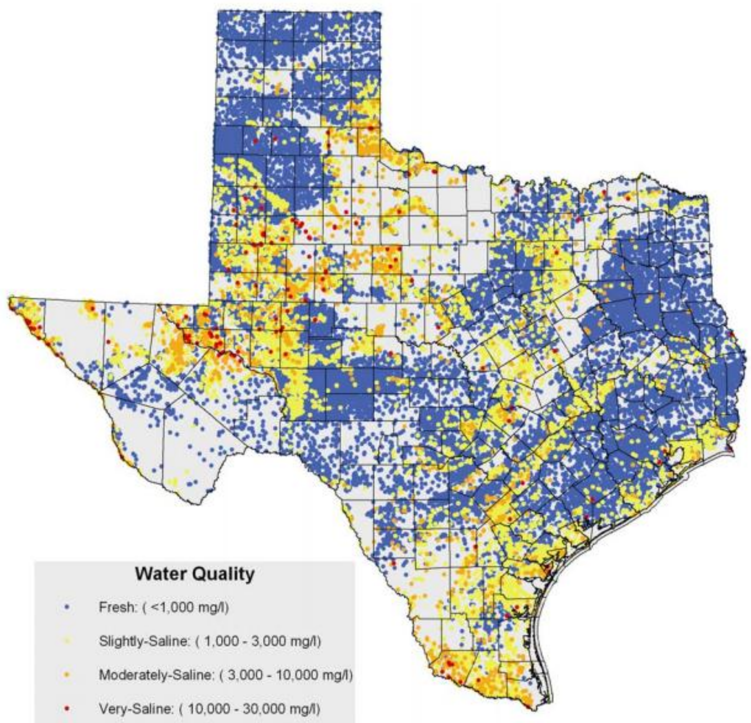

Figure 9: Distribution of Brackish Groundwater in Texas

	1,000-3,000 mg/L TDS	3,000-10,000 mg/L TDS	Total
Texas	1,758,955,300	954,858,100	2,713,813,400
Region L	300,957,900	116,809,300	417,767,200
Carrizo-Wilcox Aquifer	270,024,000	160,157,400	430,181,400
Gulf Coast Aquifer	354,429,100	168,063,600	522,492,700

Table 3: Brackish Water Supplies (in Acre-Feet)

4.1.2 HISTORICAL WATER USE IN THE EAGLE FORD SHALE

The Eagle Ford, being such a new play (only in substantial operation for roughly two years), has had an evolving water use trend. Generally, water use has been greater than other plays, as previously discussed. According to a study performed by J.P. Nicot et al. of the Bureau of Economic Geology, hydraulic fracturing in the Eagle Ford shale currently requires on average roughly five million gallons of water per well; although this number varies throughout the shale play, as can be seen in Figure 10[43]. In 2011, water use for hydraulic fracturing processes translated to a cumulative use of approximately 24 thousand acre-feet of water (over 7.8 billion gallons).[44]

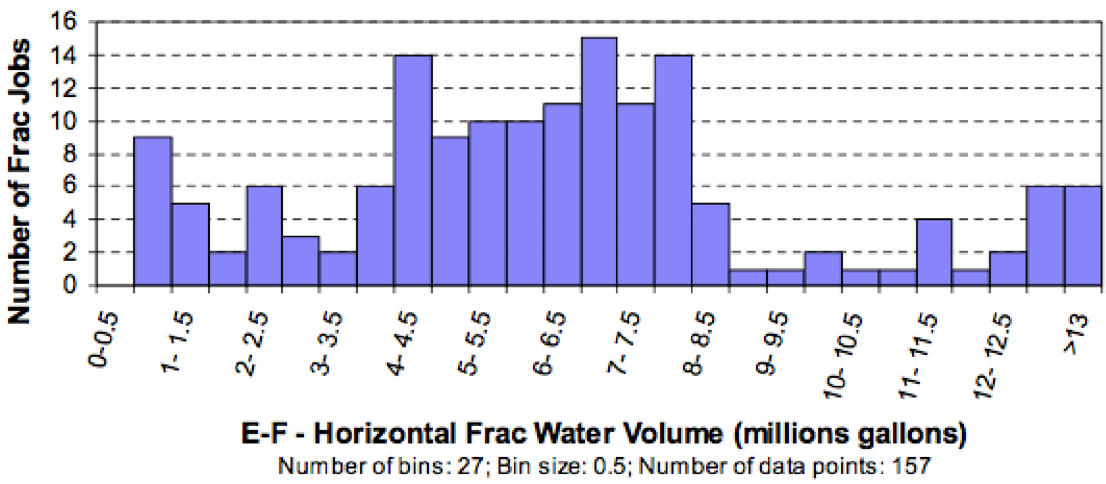

Figure 10: Horizontal Well Fracture Water Use in the Eagle Ford, Total Volume (2008 and Beyond)

The Eagle Ford is very unique, in that its water use per well has been reduced by nearly half over the past four years; this is primarily do to a shift in operational practices,

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[43] Nicot, Jean-Philippe, et al. Current and Projected Water Use in the Texas Mining and Oil and Gas Industry. *Bureau of Economic Geology.* Prepared for Texas Water Development Board. February 2011.
[44] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

from "high-volume slick-water HF [hydraulic fracture] operations to gel fracs that can carry as much proppant with much less water".[45] This decrease in both water use and type of fracture fluid base can be attributed primarily to the oil content that is being pursued, which requires a different fluid makeup for fracture stimulation; in other parts of the play, where natural gas is being extracted, greater water quantities are being used.

4.1.2.1 Current Water Quality Use in the Eagle Ford

The Eagle Ford is a prime example of a shale play that is an optimal candidate for use of lower-quality water resources. Already today, approximately 20 percent of water used for hydraulic fracturing operations in the Eagle Ford is classified as brackish.[46] For this statistic, brackish water is defined as less than 35,000 mg/L TDS content but more often less than 10,000 mg/L TDS (fresh water is classified as less than 1,000 mg/L TDS). That comes to nearly 5,000 acre-feet of water a year at 2011 consumption levels (approximately 1.6 billion gallons), which can be viewed as displaced fresh water. However, it is important to keep in mind that 80 percent of water demand is still made up of fresh water.

This significant brackish water use is likely due to the readily available and accessible aquifers with substantial brackish water sections throughout the Eagle Ford region—primarily the Carrizo-Wilcox and the Gulf Coast aquifers. (Refer to brackish water supplies listed in Table 3 above.)

[45] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.
[46] Id.

4.1.2.2 Current Water Sources for Hydraulic Fracturing in the Eagle Ford

Water sourcing for hydraulic fracturing operations in the Eagle Ford is fairly unified. Ninety percent of water use is said to be groundwater[47], as surface water is not readily available throughout this region. The primary aquifer that underlies the Eagle Ford shale is the Carrizo-Wilcox, shown in red (both solid and striped) in Figure 12[48]; the Gulf Coast aquifer is also adjacent to development activities (shown in yellow).

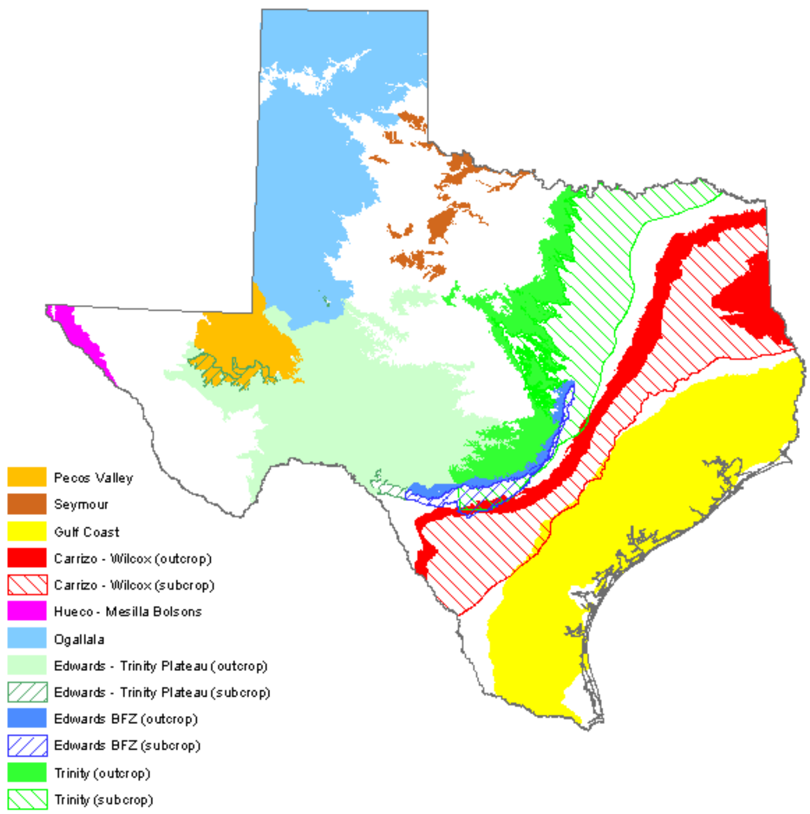

Figure 12: Map of Major Aquifers in Texas

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[47] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

[48] Major Aquifers. *Texas Water Development Board.* Accessed on 03/25/13, http://www.twdb.state.tx.us/groundwater/aquifer/major.asp.

As for surface water (roughly the remaining ten percent of water supply), the Rio Grande is the primary river system that runs through the Eagle Ford region, as can be seen in Figure 13[49]; this map shows the surface water availability across the state of Texas.

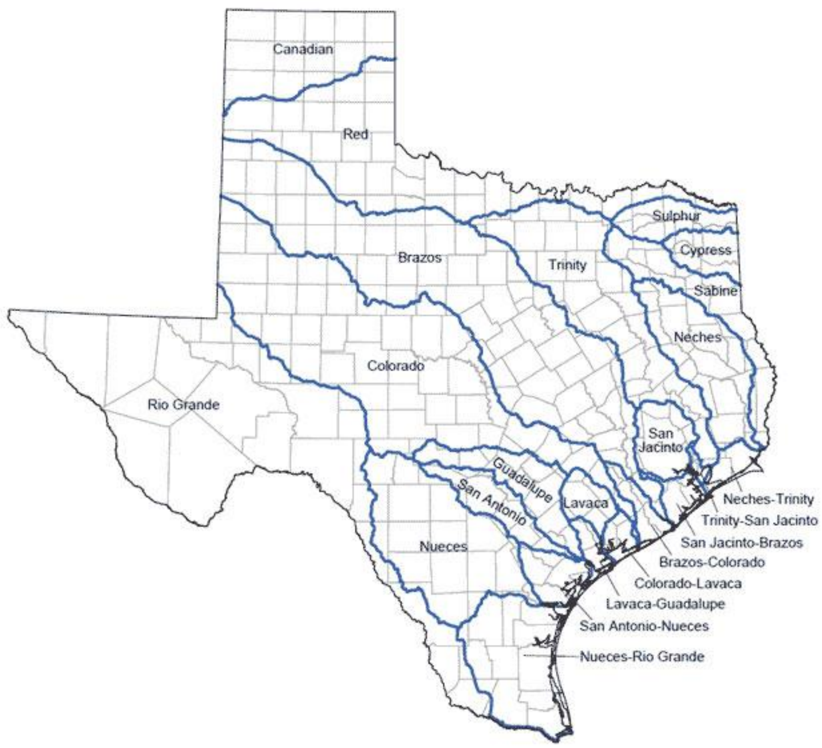

Figure 13: Map of River Systems in Texas

Alternative water supplies are currently unavailable in this region due to a variety of reasons, logistically or other. For example, wastewater streams from other industries, such as municipal wastewater treatment plants, are not generally used due to tedious regulatory requirements placed on wastewater reuse by the Texas Commission on Environmental Quality (TCEQ). Extensive requirements including considerable

[49] River Basins & Reservoirs. *Texas Water Development Board.* Accessed on 03/25/13, http://www.twdb.state.tx.us/surfacewater/rivers/index.asp.

paperwork and detailed transportation stipulations (colored/labeled pipes, etc.) make reuse of this water source prohibitively expensive and time-consuming.[50]

Apart from regulatory setbacks, logistics are another important point of consideration when determining available water sources—it must be close to the area where the water is needed to limit transportation costs to make use of a particular water supply economical. As groundwater is relatively inexpensive and widespread throughout this region, finding alternative water sources that are both logistically feasible and economical is challenging.

4.2.1.3 Regulatory Oversight of Water Withdrawals for Hydraulic Fracturing

In Texas, groundwater is, generally-speaking, owned by the landowner and managed with the "Rule of Capture", which is defined as follows: "landowners may pump as much water as they choose, without liability to surrounding landowners who might claim that the pumping is depleting their wells. There are very few restrictions to the rule of capture."[51] Because of this framework, operators routinely approach landowners directly for water supplies, and landowners have generally been receptive, as water sales are quite lucrative compared to other uses for their water.

However, certain regulations do apply through the Railroad Commission of Texas (RRC) and other government entities, pertaining to water well construction among other

[50] Steve Jester (Senior Principal Environmental Engineer, ConocoPhillips), interview by Megan Leseberg. By phone. 03/18/13.

[51] Water Use in Association with Oil and Gas Activities Regulated by the Railroad Commission of Texas. *Railroad Commission of Texas.* Accessed on 04/08/13, http://www.rrc.state.tx.us/barnettshale/wateruse.php.

stipulations. Specifically, operators may be subject to groundwater conservation district (GCD) control. Figure 11[52] is a map of the GCDs found across the state.

GCDs are government entities established throughout the state (often coinciding with county lines); they are "required to develop and implement a management plan for effective management of their groundwater resources"[53]. Through these plans, GCDs may inflict restrictions on the Rule of Capture, limiting available withdrawal amounts for landowners and subsequently operators as well. Restrictions and requirements for water withdrawals for shale development by GCDs vary considerably. This can be attributed to the size of the GCD, funding, as well as confusion that has proliferated this aspect of the industry due to a provision in the Texas Water Code offering an exemption to the oil and gas industry—"a groundwater district cannot require a permit if the well is drilled to supply water for a rig doing 'drilling and exploration operations' for an oil and gas well"[54]. This has created a grey area as to what stage of the development process hydraulic fracturing appropriately falls under—drilling or production.

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[52] Groundwater Conservation Districts. *Texas Water Development Board.* Accessed on 04/24/13, http://www.twdb.state.tx.us/mapping/doc/maps/gcd_only_8x11.pdf.

[53] Id.

[54] Galbraith, Kate. Fracking Groundwater Rules Reflect Legal Ambiguities. *The Texas Tribune.* 03/13/13. Accessed on 05/06/13, https://mail-attachment.googleusercontent.com/attachment/u/1/?ui=2&ik=49b9df7cac&view=att&th=13e1d8be04de5ee9&attid=0.1&disp=inline&safe=1&zw&saduie=AG9B_P-xPoj-Bq5ZbYimTB6QOSvY&sadet=1367860680225&sads=Hvxjio4B53kNXJpKUr4iRvyedPU.

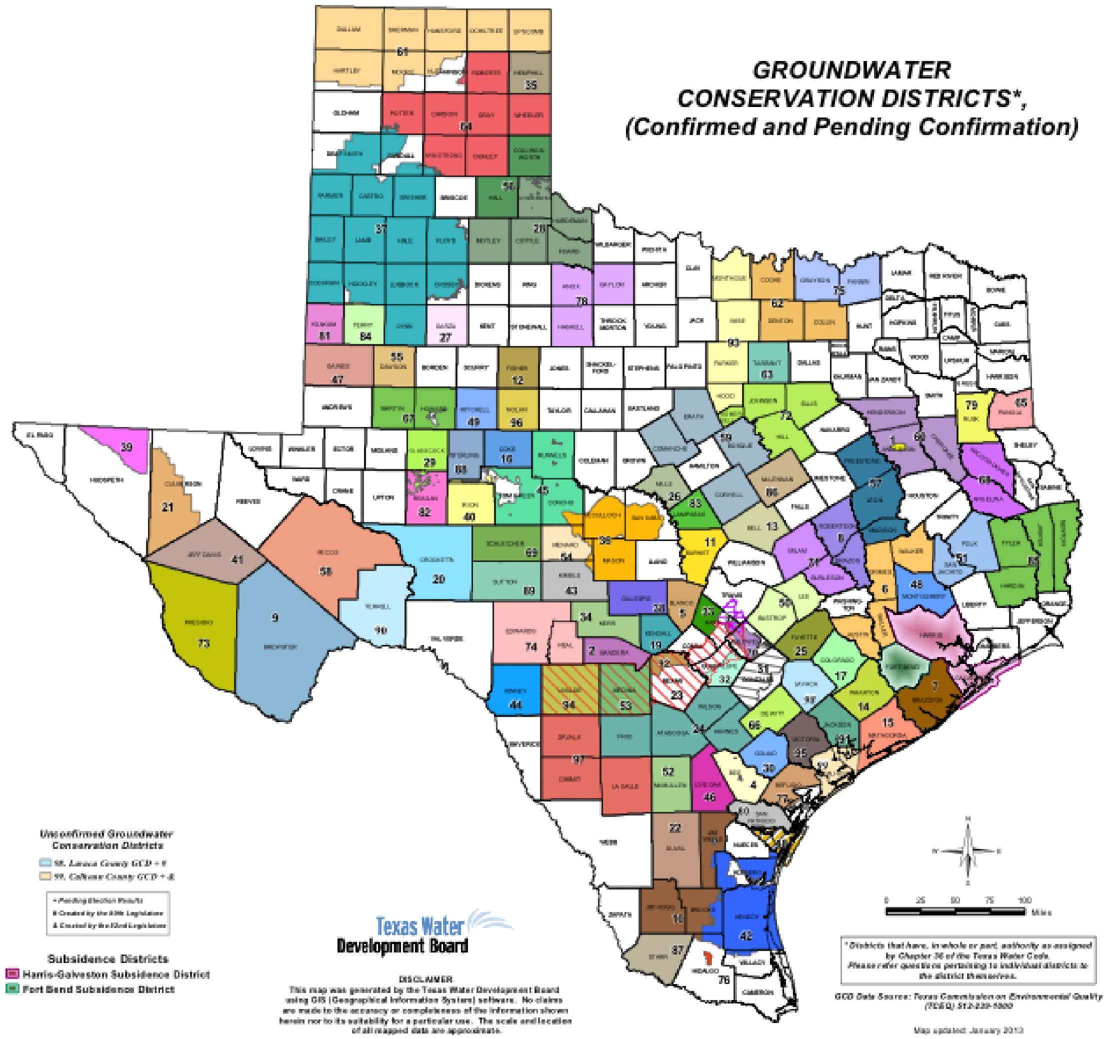

Figure 11: Map of Groundwater Conservation Districts (Confirmed and Pending) in Texas

The spectrum of regulatory requirements is exemplified through the following three GCDs, all of which are experiencing substantial shale development from the Eagle Ford: 1) The Evergreen Underground Water Conservation District (one of the most aggressive GCDs in the state, which encompasses Atascosa, Frio, Wilson, and Karnes counties) requires operators to obtain a permit for hydraulic fracture-related withdrawals, limits withdrawals to two acre-feet of water per acre of land per year, and requires monthly pumping reports; 2) the Wintergarden Groundwater Conservation District (a more lax GCD, which includes Dimmit County) requires operators to register hydraulic fracturing water wells, but with no restrictions on water use or reporting; meanwhile, 3) the McMullen County Groundwater Conservation District requires water well registration and reporting of withdrawals but no permit.[55]

Two bills are currently in the Texas legislature that could potentially change this regulatory environment for shale developers. Senate Bill 873 would clarify the current Texas Water Code ambiguities discussed above, preventing GCDs from exempting water wells used for hydraulic fracturing, requiring the issuance of permits by GCDs for all water withdrawals related to fracturing operations.[56] The other proposed bill, House Bill 3317, would exempt hydraulic fracturing-related water wells from permitting, but "would require those water well operators to comply with other requirements established by the groundwater district, such as limits on how much water can be pumped. It would also require the well operators to report how much water is being used".[57] Both bills have obtained support by various entities, but it remains to be seen which way the Legislature will go.

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[55] Galbraith, Kate. Fracking Groundwater Rules Reflect Legal Ambiguities. *The Texas Tribune.* 03/13/13. Accessed on 05/06/13, https://mail-attachment.googleusercontent.com/attachment/u/1/?ui=2&ik=49b9df7cac&view=att&th=13e1d8be04de5ee9&attid=0.1&disp=inline&safe=1&zw&saduie=AG9B_P-xPoj-Bq5ZbYimTB6QOSvY&sadet=1367860680225&sads=Hvxjio4B53kNXJpKUr4iRvyedPU.
[56] Galbraith, Kate. Fracking Groundwater Rules Reflect Legal Ambiguities. *The Texas Tribune.* 03/13/13. Accessed on 05/06/13, https://mail-attachment.googleusercontent.com/attachment/u/1/?ui=2&ik=49b9df7cac&view=att&th=13e1d8be04de5ee9&attid=0.1&disp=inline&safe=1&zw&saduie=AG9B_P-xPoj-Bq5ZbYimTB6QOSvY&sadet=1367860680225&sads=Hvxjio4B53kNXJpKUr4iRvyedPU.
[57] Id.

As for surface water resources, according to Texas water law, surface water—creeks, rivers, and bays—is owned by the State. "Anyone who diverts such surface water must have authorization—or a water right—from the State of Texas through the Texas Commission on Environmental Quality (TCEQ)."[58] Temporary Water Right permits are available for short-term use of ten acre-feet of water or less, for one year or less; however, in times of drought, all temporary water rights permits can be suspended by TCEQ, making this water supply less reliable when compared to other water sources.

To summarize the current water use environment in the Eagle Ford, water requirements per hydraulic fracturing operation have declined over the past four years, currently averaging approximately five million gallons of water per well. However, this is still a significant amount of water required to sustain continued development; in 2011, water use for hydraulic fracturing operations totaled 24 thousand acre-feet of water (over 7.8 billion gallons). This water is primarily supplied by available groundwater sources—the Carrizo-Wilcox and Gulf Coast aquifers—an estimated 20 percent of which is classified as brackish water. Lack of available surface water and strict wastewater use regulations prevent diversification of water supply sources.

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[58] Water Use in Association with Oil and Gas Activities Regulated by the Railroad Commission of Texas. *Railroad Commission of Texas.* Accessed on 04/08/13, http://www.rrc.state.tx.us/barnettshale/wateruse.php.

4.2 Recycle and Reuse of Flowback and Produced Water

4.2.1 Overview

As discussed in Chapter 2, following the hydraulic fracturing process—the injection of millions of gallons of fracture fluid deep into the subsurface—a portion of the originally injected fluid returns to the surface deemed "flowback water". This water production can begin within hours of injection and last over a month, depending on the shale play, and may account for less than 10 percent to more than 70 percent of the original fracture fluid volume.[59] The quality of this flowback water depends on a number of factors such as the quality of the original fracture fluid water, the chemicals used, and the time residing in the formation; however, generally speaking, the initial flowback fluid is of the highest quality and thus can be "reused with little treatment (filtration and/or mixing [with new fresh water])"[60].

Along with, but generally following flowback water production is "produced water", which is defined here as water originally housed in the shale formation itself or in surrounding formations with connectivity to the shale directly above or below. This fluid has resided in the formation for millions of years, resulting in the leaching of a host of minerals and metals into the fluid solution. The quality of this fluid varies significantly from play to play, differing in levels of salinity, TDS (total dissolved solids), and mineral content, among a variety of other constituents.

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[59] Water Management Associated with Hydraulic Fracturing: API Guidance Document HF2. *American Petroleum Institute.* First Ed. June 2010.

[60] Nicot, Jean-Philippe et al. Current and Projected Water Use in the Texas Mining and Oil and Gas Industry. *Bureau of Economic Geology.* Prepared for Texas Water Development Board. June 2011.

Regardless of the classification of this water—flowback versus produced water—this wastewater must be managed by the operator—either properly handled, stored, transported, and disposed of in a Class II disposal well or treated onsite or offsite for reuse in a subsequent fracture job or release into the environment. Depending on the regulatory environment, land farming may be a permissible disposal strategy as well. Treatment for reuse in a subsequent fracture job is rapidly becoming a feasible option with successful treatment and reuse facilities currently in place across nearly every active shale play in the US.

The quality of the water, however, plays a huge role in determining the available and proper treatment system; "characteristics that may influence water management options for fracturing operations include concentrations of hydrocarbons (analyzed as oil and grease), suspended solids, soluble organics, iron, calcium, magnesium, and trace constituents such as benzene, boron, silicates, and possibly other constituents"[61]. One class of constituents of special concern is naturally occurring radioactive materials, commonly referred to as NORM. These materials are not common in all shale plays but have been detected in some spots, specifically in the Marcellus shale. The presence of radioactive material increases treatment difficult and consequently cost. Additionally, TDS concentrations in flowback/produced wastewater can range from 5,000 to 100,000

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[61] Water Management Associated with Hydraulic Fracturing: API Guidance Document HF2. *American Petroleum Institute.* First Ed. June 2010.

parts per million (ppm), and total suspended solids (TSS) can range from 100 to 3,000 ppm.[62]

The variability and number of contaminants make treatment challenging, as one treatment technology will not work for every operation, and modifications in treatment may be needed as flowback fluids vary in their chemical makeup and concentrations even throughout the life of the well. If the contaminants are not properly removed during the treatment process, they can create problems during subsequent fracture stimulations, such as scaling and precipitation, which reduce permeability within the formation, resulting in decreased gas production and possible equipment damage. Therefore, an initial, in-depth chemical analysis of the flowback water is essential to determine the degree of treatment needed, as well as suitable treatment technologies.

The desired end product of the treated flowback fluid must be a major consideration in determining a recycling strategy. The technology must be able to treat the wastewater to the quality that is required for subsequent hydraulic fracture stimulations. Additional detailed analyses must be performed to establish these quality requirements, as well as determining an adequate chemical combination that will achieve the desired results in the following fracture stimulation.

Many other elements also factor into the wastewater management equation. As stated above, the quality of the flowback fluid is the primary determent in choosing the appropriate technology capable of handling the particular fluid constituents. Additionally,

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62 Horner, Patrick P. et al. Shale Gas Water Treatment Value Chain – A Review of Technologies, including Case Studies. *Society of Petroleum Engineers.* 2011. SPE 147264.

the treatment capacity as compared to the volume and rate of flowback fluid, as well as the subsequent volume and timing of demand for future fracture stimulations, poses a dilemma of logistics. To successfully reuse flowback fluids, the treated water must be available, in the necessary quantity and quality, when and where needed.

Efficiency is another determining factor in the selection of a particular treatment method; most treatment technologies have a waste stream, for example, a highly concentrated brine solution, associated with the treatment process. Operators are responsible for the proper management and disposal of this waste stream. Therefore, the highest efficiencies possible are sought out for these processes to reduce disposal costs.

Finally, the treatment system footprint must be considered when determining the appropriate technology. Shale development requires a robust infrastructure and fleet of trucks, generators, tanks, among other equipment. In order for on-site treatment to be feasible, the system must fit within the well pad site in a convenient and manageable manner. However, offsite treatment systems at a centralized location are another option for companies with intensive development operations in a generally localized area.

With those constituencies in mind, there are many different types of treatment that are available today, with more continuously being developed. The next section will discuss different treatment methods in greater detail.

4.2.2 TREATMENT TECHNOLOGIES

There are numerous different treatment technologies available today; however, they all fall within three general categories of treatment, or some combination thereof—thermal, physical, and chemical.

Thermal treatment includes processes such as evaporation, distillation, and crystallization. Distillation, such as mechanical vapor recompression, is generally less mobile, with higher costs; however, the process removes salt, creating a more user-friendly recycled fluid and lowers risk of contamination with transportation.[63]

Physical treatment processes involve the removal of solids through a physical media, for example a membrane, with filtration capabilities ranging in size from large rock particles to the nano-particle scale. Nano/ultra-filtration removes suspended solids and some dissolved solids, although salt removal may not be possible with this process—especially with mobile units.[64] Reverse osmosis, however, is a type of filtration system that can be mobile and is adequate for salt removal; these systems are generally more economic than evaporative systems but are limited by TDS levels of around 50,000 parts per million (ppm).[65] Though it is important to note that with reverse osmosis systems, higher TDS levels will result in greater concentrated waste streams, and consequently, less reusable water; and though technically feasible, scaling also becomes a more critical issue with higher salinities.

Chemical processes intuitively involve a chemical constituent or oxidation process. Often, two or more of these treatment techniques will be combined to increase the efficiency and/or speed of the process.

Each treatment option—thermal, physical, or chemical—has its associated benefits and weaknesses. For example, "Reverse osmosis works for particles that are

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[63] Dunkel, Michael. Evolution of Water Management in 2013: A Producers Perspective. *Pioneer Natural Resources.* Water Development for Shale Plays Conference. 02/26/13.
[64] Id.
[65] Id.

about 1 nm in size and that seems to cover most contaminants, but it is economical only at lower values of dissolved solids…Through distillation one can obtain pure, contaminant-free water, out of virtually any aqueous feed but the cost of energy required for this process is high."[66] As previously stated, a combination of these treatment processes is usually developed, tailored to the waste fluid in order to achieve proper treatment and at the desired speed and capacity to allow for economic reuse in subsequent fracture jobs.

Two technologies specifically have been widely used throughout the industry—Aqua-Pure's NOMAD and Purestream's Mobile Treatment system.

Aqua-Pure technology is being used in the Barnett, Marcellus, and Eagle Ford shales. Their NOMAD mobile treatment "consists of three easy-to-transport modules which occupy a small footprint in the field. The NOMAD is equipped with a natural gas generator and can even be monitored and operated remotely."[67] The unit utilizes evaporation to treat the wastewater; "The feedwater is boiled to produce steam, leaving behind all dissolved solid contaminants. The steam is then condensed into pure distilled water."[68] Additionally, Aqua-Pure has found a use for the high-brine concentrated waste stream, selling it, along with other byproducts of the treatment process, to other industries, decreasing overall costs of treatment.

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[66] Pierce, Dale A. et al. Water Recycling Helps with Sustainability. *Society of Petroleum Engineers.* 2010. SPE 134137.
[67] Mobile Primary Treatment. *Fountain Quail Water Management: Aqua-Pure.* Accessed on 12/08/12, http://www.aqua-pure.com/technology/mobile/mobile.html.
[68] MVR Evaporation. *Fountain Quail Water Management: Aqua-Pure.* Accessed on 12/08/12, http://www.aqua-pure.com/technology/evaporation/evaporation.html.

Purestream has two treatment systems, an Induced Gas Flotation (IGF) module to treat fluids with high TSS and hydrocarbon concentrations, as well as an Accelerated Vapor Recompression (AVARA) module for produced water purification, specifically high brine concentrations. To increase efficiencies, these systems capture the waste heat from power generation to help fuel the process. Ease of use has been a priority of Purestream; "These systems have been engineered to operate on a mobile platform so they can be configured to meet the specific needs of the producers…Additionally, units can be added or removed from the site to allow for fluctuations in produced water volumes."[69] Purestream technologies are being implemented in production activities within the Marcellus, Bakken, Fayetteville, Woodford, and Eagle Ford shales.

4.2.3 High-Level Economic Analysis of Recycling and Reuse as a Management Method

Water management typically makes up between five and fifteen percent of overall shale gas drilling and completion costs[70]—a very significant portion of operational costs. Therefore, multiple factors go into determining the optimal water management strategy; "[It] is a function of water sourcing and disposal cost and availability, formation geology and how that impacts both flowback water chemistry and frac fluid compatibility, the

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[69] Mobile Treatment. *Purestream Technology.* Accessed on 12/09/12, http://purestreamtechnology.com/index.php/mobile-treatment.

[70] Slutz, James et al. Key Shale Gas Water Management Strategies: An Economic Assessment Tool. *SPE International/APPEA.* SPE 157532. 2012.

regulatory environment, and the availability of commercialized and cost-effective technology."[71]

Like most industries, cost is generally the prevailing factor—assuming no regulatory restrictions on disposal. High costs have been said to be the overriding barrier to implementation of treatment technologies for reuse of flowback fluids in the past; however, new analyses question the reality of this assumption. Tom Whalen, Vice President of Water Management at Baker Hughes, has a different idea; "This division of responsibility [for the total cost of water] creates a false economy for water, artificially lowering the price, and distorting the true cost."[72] He feels, "The economics are right. Scores of successful projects prove that produced and flowback water can be treated at a lower cost than acquiring and using fresh water. And the treatment technology certainly exists. The oil field is overrun today with companies claiming to have all manner of technologies to treat water."[73]

When evaluating the cost of alternative disposal options, such as reinjection through a Class II disposal well—as is commonly done in Texas—every step of the process must be included in order to obtain a truly accurate cost figure.

First, the fluid must be transported offsite by either pipeline or truck, and with this comes an associated cost. A general rule of thumb for costs of transportation by truck has

[71] Horner, Patrick P. et al. Shale Gas Water Treatment Value Chain – A Review of Technologies, including Case Studies. *Society of Petroleum Engineers.* 2011. SPE 147264.
[72] Whalen, Tom. The Challenges of Reusing Produced Water (Guest Editorial). *Journal of Petroleum Technology*. November 2012. Accessed on 11/12/12, http://www.mydigitalpublication.com/publication/?i=130685.
[73] Id.

been estimated at $1.00 per barrel of fluid per hour of truck time.[74] Depending on the distance of the nearest disposal well from the well pad, this cost could increase very quickly. Additionally, the cost of the actual injection process must be included, which has been estimated at $1.50 to $2.00 per barrel of waste fluid[75]. Finally, the cost of purchasing fresh water for the subsequent fracture jobs must also be incorporated into the analysis, as well as transportation costs to bring the fresh water to the well site. This price varies, depending on location, availability, competing water users, among other factors; but a rough estimate for groundwater in Texas can be assumed at less than $0.04 per barrel[76]. However, other sources (specifically the Texas Water Recycling Association) have estimated landowner-set prices for their water at between $0.35 and $0.50 a barrel.[77]

This could yield an initial total cost of between $2.54 and $3.50 per barrel of fluid (including the cost of purchasing new fresh water) for one hour of truck time for transporting waste fluids—with every additional hour of truck time, this cost will obviously increase. Additionally, if the fresh water source is not located onsite, increased

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74 Hoopes, Jonathan D. Storing Water On-Site to Reduce Transportation Costs and Maximize Efficiencies. *Green Hunter Energy Inc.* 4th Annual Water Development for Shale Plays Conference. Houston, Texas, 02/26/13.

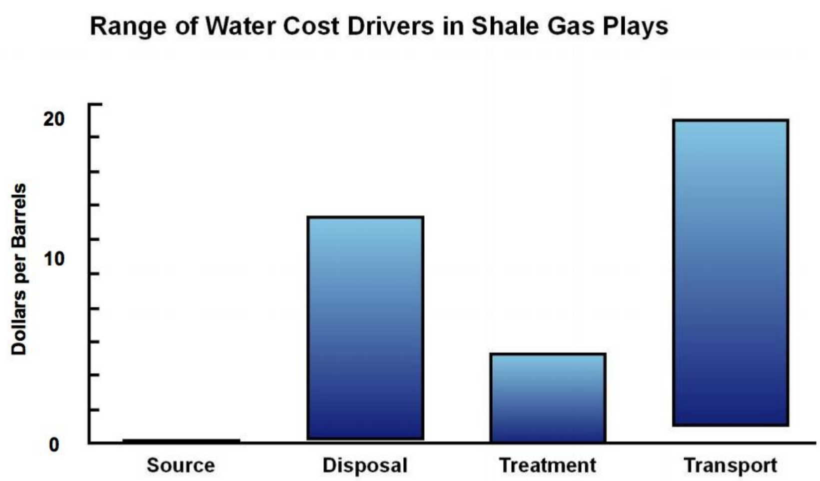
75 Rassenfoss, Stephen. From Flowback to Fracturing: Water Recycling Grows in the Marcellus Shale. *Journal of Petroleum Technology: Society of Petroleum Engineers.* July 2011. Accessed on 05/06/13, http://www.spe.org/jpt/print/archives/2011/07/12Marcellus.pdf.

76 The cost of fresh water was estimated by obtaining base water rates from the San Antonio Water Systems (SAWS) website ($0.1148/100 gallons), http://www.saws.org/service/rates/general.cfm. The SAWS base rate was chosen because San Antonio is nearly entirely dependent on groundwater for their fresh water supply, as is development in the Eagle Ford, so costs may be comparable. This estimate is assumed to be high, as this is the charge associated with obtaining treated, potable water, whereas water purchased for hydraulic fracturing operations is untreated, simply extracted from the aquifer. To obtain the true cost of this water, additional transportation costs must be applied to this approximate base rate.

77 Galbraith, Kate. In Texas, Water Use for Fracking Stirs Concerns. *The Texas Tribune.* 03/08/13. Accessed on 05/06/13, http://www.texastribune.org/2013/03/08/texas-water-use-fracking-stirs-concerns/.

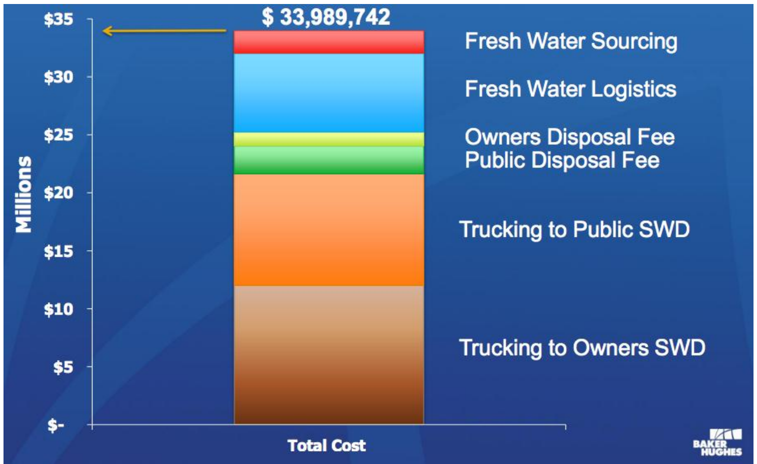
costs will occur from those transportation fees as well, resulting in a total cost of likely over $5.00 per barrel of fluid.

Truck visits for flowback water removal alone can range on average between 200 and 300 visits per well; for a well pad (with multiple wells), this number can be as much as 1,800—roughly 28 percent of total trucking needs for the entire development lifecycle.[78] This can result in very significant operational costs. Figure 14[79] compares costs of different aspects of the wastewater management process; although these ratios are variable depending on location and many other factors. It is apparent—transportation is the major constituent, making up the majority of disposal costs. Figure 15[80] examines the issue from a different perspective, comparing costs per barrel with changes in both transportation method (truck versus pipeline) and different storage options.



[78] Dale, Walter. Sustainable Development of Completions. *Halliburton.* 4th Annual Water Development for Shale Plays Conference. Houston, Texas, 02/26/13.
[79] Gay, Marcus Oliver. The Future of Water in Unconventionals. *IHS.* 4th Annual Water Development for Shale Plays Conference. Houston, Texas, 02/26/13.
[80] Dawson, Kent. Understanding and Optimizing the Water Management Value Chain: Integrated Solutions for the Life of Your Well. *Baker Hughes.* 4th Annual Water Development for Shale Plays Conference. Houston, Texas, 02/26/13.

Figure 14: Range of Water Cost Drivers in Shale Gas Plays



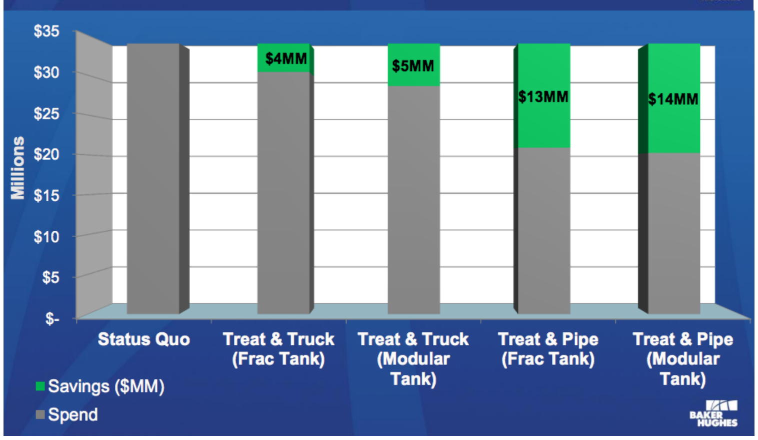


Figure 15: Cost Estimates Based on a Two-Year Study of 170 Wells with Hauling and Disposal of Water being Three Hours Away

Removal or even reduction of a portion of these transportation expenses can dramatically impact waste management costs. Although treatment costs may appear high, for every barrel of wastewater that is recycled, the operator can reduce or even eliminate the following expenses: 1) a barrel of fresh water and the cost to transport that water; 2) over 95 percent of disposal volumes and associated costs; 3) cost of flowback/produced water transport (when on-site treatment is utilized); and 4) cost of brine addition for clay stabilization (often a certain level of salinity remains post-treatment).[81] However, despite potential economic attractiveness, logistics is yet another prohibiting factor, one that will be discussed in greater detail in Chapter 5.

4.2.4 RECYCLING AND REUSE ON A NATIONWIDE SCALE

Notwithstanding economic and logistical obstacles, recycling and reuse can be found to some extent in nearly every shale play across the country, although the percentage of total water use provided by these recycling efforts may be insignificant due to a number of different factors, such as availability of underground disposal, cost, and regulation.

Recycling and reuse of flowback and produced water is said to have originated in the Barnett shale[82], the same place where hydraulic fracturing made its break. However, due to the geology throughout this play—specifically the Ellenberger Limestone—the availability of cheap underground disposal wells and ample, low-cost fresh water supplies have prohibited cost effective treatment for reuse. Estimates of current recycled water use for fracturing activities in the Barnett are approximately five percent of total water use.[83]

The exact opposite is true for the Marcellus shale located in the northeastern United States; it is a very unique play for recycling. In mid-April of 2011, the Pennsylvania Department of Environmental Protection (PDEP) prohibited 15 public

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[81] Dale, Walter. Sustainable Development of Completions. *Halliburton.* 4th Annual Water Development for Shale Plays Conference. Houston, Texas, 02/26/13.
[82] Duncan, Ian. Environmental Impact of Shale Gas Production: Implications for Developing Effective Regulatory Frameworks. *Energy Institute.* February 2012.
[83] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

water treatment plants (POTWs) from handling wastewater from Marcellus hydraulic fracturing operations[84] because these facilities were unable to adequately treat the high salinities and other constituents present in the wastewater. Additionally, Pennsylvania's geology is not conducive to underground disposal via injection, as is the case in other parts of the country, specifically Texas and Oklahoma. This leaves operators with two choices for managing their wastewater—transporting the wastewater to Ohio for disposal in underground injection wells or treatment for reuse. As was discussed previously, trucking costs can be prohibitively expensive; and as a result, most operators have turned to treatment as their management solution. At the time of this PDEP action, an estimated two-thirds of wastewater was already being recycled; that number is said to have increased with this recent regulatory change.[85] One company, Range Resources, said to have recycled and reused 96 percent of its wastewater in the Marcellus in 2010.[86]

To gage these high treatment rates' effects on total water demand, roughly 10 to 30 percent of the water injected returns to the surface as flowback in the Marcellus[87]; with nearly 100 percent reuse, this recycled water accounts for roughly between 10 and 30 percent of total water use. These high success rates for recycling and reuse of flowback and produced waters show the true potential of these technologies and will likely influence operations in other shale plays in the future. However, it is important to

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84 Rassenfoss, Stephen. From Flowback to Fracturing: Water Recycling Grows in the Marcellus Shale. *Journal of Petroleum Technology.* July 2011. Accessed on 03/13/13, http://www.spe.org/jpt/print/archives/2011/07/12Marcellus.pdf.

85 Rassenfoss, Stephen. From Flowback to Fracturing: Water Recycling Grows in the Marcellus Shale. *Journal of Petroleum Technology.* July 2011. Accessed on 03/13/13, http://www.spe.org/jpt/print/archives/2011/07/12Marcellus.pdf.

86 Id.

87 Id.

keep in mind that even though 10 to 30 percent of water use is recycled—a much greater amount than other shale plays—70 to 90 percent of the water demand for hydraulic fracturing must still be met through fresh water or some alternative source; this could be anywhere from 3.85 to 4.95 million gallons a well (according to Chesapeake's water average water use shown previously in Table 2), a very significant quantity.

Success of recycling efforts in other shale plays is variable. The Fayetteville shale generally yields very high quality flowback/produced water as compared to other plays, allowing operators to reuse a majority of initially produced water; Chesapeake Energy has reached reuse rates of 80 percent per well, accounting for approximately six percent of total water needed to fracture a new well.[88] On the other hand, little to no recycling is going on in the Haynesville shale; the produced water is low in both volume and in quality, greatly reducing the feasibility of treatment and reuse.[89] Nicot et al. found recycling averages for the portion of the Haynesville shale in Texas to be around five percent.[90] Recycling efforts in the Eagle Ford will be discussed in a later section.

Encouragingly, recycling and reuse efforts can be found across the nation, in nearly every shale play. Although current rates only make up a small percentage of water demand for continued development, it is a starting point, and hopefully as technology continues to improve, these rates too will increase.

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88 Mathis, Mike. Shale Natural Gas – Water Use Management: ICWP Annual Meeting – St. Louis, MO. *Chesapeake Energy.* October 11-14, 2011. Accessed on 03/13/13, http://www.icwp.org/cms/conferences/Mathis14Oct2011.pdf.

89 Mathis, Mike. Shale Natural Gas – Water Use Management: ICWP Annual Meeting – St. Louis, MO. *Chesapeake Energy.* October 11-14, 2011. Accessed on 03/13/13, http://www.icwp.org/cms/conferences/Mathis14Oct2011.pdf.

90 Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

4.2.5 RECYCLE AND REUSE IN THE EAGLE FORD

Although recycle and reuse of produced and flowback water has proven to be very successful—even economical—in some shale plays, such as the Marcellus, the Eagle Ford shale has yet to see these efforts. Essentially no recycling and reuse of flowback and produced water is currently being undertaken in this region.[91] This can largely be attributed to the very small amounts of flowback water that are produced. Nicot et al. estimated the flowback rates in this play to be at roughly 20 percent of the originally injected fluid[92]; however, after talking to multiple large Eagle Ford operators in this play, this number may actually be closer to ten percent. However, there is a lot of discrepancy with flowback approximations in the Eagle Ford, primarily because the amount of flowback is a function of time—percentages fluctuate depending on how flowback is defined. For example, flowback may be referred to as water produced within the first three weeks following injection. Percentages may change drastically when the timeframe is extended to a year or more.

For this context, the immediate flowback will be the focus, as that water is most likely to be recycled due to available infrastructure and adjacent well development, which has been estimated at between 10 and 20 percent of the originally injected fluid. Further discussion as to the reasons behind the current lack of recycling is in the following section, along with the potential future wastewater management activity.

Although when compared to total water use, recycling makes up essentially zero percent, there are a few active operations currently in the play. One specifically utilizes

[91] Id.
[92] Id.

Aqua-Pure's wastewater recycling technology, referenced earlier. In June 2011, Aqua-Pure entered the Eagle Ford through a subcontracting agreement with NAC Services, LLC, an affiliate of Noise Attenuation Construction Services. Two NOMAD units were installed in a centralized water purification treatment center in Kenedy, Texas; it has the capacity to treat approximately 5,000 barrels of flowback/produced wastewater per day.[93] The center is also selling the concentrated brine and other byproducts to other industries, increasing the economic viability of the process.

The success of this project may likely spur greater utilization of recycling efforts across the play. However, there is still the reality of flowback/produced water production—the Eagle Ford shale only produces between 10 and 20 percent of originally injected water following a fracture stimulation. This severely limits the amount of fresh water that recycling efforts can replace. Other alternatives such as use of brackish water will be necessary to decrease demand on fresh water resources in this generally arid area.

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[93] Eagle Ford Shale (South Texas). *Fountain Quail Water Management.* Accessed on 03/25/13, http://www.aqua-pure.com/operations/shale/ford/ford.html.

4.3 Operator Motivation and Action

As was introduced in Chapter 3, companies with large operations in the Eagle Ford were contacted, and interviews were conducted to ascertain current wastewater management practices, as well as drivers for these decisions. With a clear understanding of the real-life factors that affect these decisions, a reasonable estimation of potential future recycling efforts could be made (following in Chapter 5).

All of the companies that were interviewed had the same responses regarding current wastewater management strategies, as well as general supporting evidence and rationales justifying their actions. For this reason, I will not distinguish between the companies specifically in the following sections; I will speak in general terms, considering this group as a sample, representing Eagle Ford operators today.[94,95,96,97,98]

Operations conducted by these companies make up approximately 23 percent of total Eagle Ford development. Although this representation is relatively small, due to the sheer number of different operators in the Eagle Ford—over 200 active operators[99]—it is assumed that the larger companies are those most likely to incorporate recycling

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[94] Steve Jester (Senior Principal Environmental Engineer, ConocoPhillips). Interview by Megan Leseberg. By phone. 03/18/13.

[95] Hughes, Keystone (Asset Manager, Eagle Ford Shale, Chesapeake Energy Inc.). Interview by Megan Leseberg. By phone, 03/12/13.

[96] Dunkel, Michael (Director, Sustainable Development, Pioneer Natural Resources). Interview by Megan Leseberg. In person, 02/26/13.

[97] Spicer, Pete (Senior Environmental Scientist, ConocoPhillips). Interview by Megan Leseberg. By phone, 03/11/13.

[98] Dale, Walter (Strategic Business Manager, Halliburton). Interview by Megan Leseberg. By phone, 03/14/13.

[99] Eagle Ford Shale Operators and Active Companies. 2012. *Ked Interests, LLC.* Accessed on 04/08/13, http://eaglefordshale.com/companies/.

technologies into their operations, as economies of scale are essential for economically feasible activities. Therefore, to estimate fresh water displacement through the use of recycling technologies, and the future potential of these efforts, large operators—like those interviewed—are the primary target.

4.3.1 Wastewater Management Strategies of Large Eagle Ford Operators

Currently, in the Eagle Ford shale, operators are primarily disposing of wastewater (both flowback and produced waters) in Class II injection wells. This type of injection well is prominent throughout the Eagle Ford shale, shown in Figure 16[100], offering a cheap, available management method at operators' disposal. Due to the vast numbers of Class II wells and the combination of relatively cheap fresh water to supply additional fracture operations, disposal through injection into the subsurface has been the optimal strategy thus far in this play.

4.3.2 Plans for Future Recycling and Reuse Efforts

For most companies, the potential for future recycling efforts looks dim, as the economics and logistics of disposal through Class II wells is currently optimal. However, regulatory shifts in the future may bring change, potentially forcing companies to partake in recycling/treatment efforts. Proposed bills are already in the Texas Legislature, which will be discussed in greater detail in a following section.

[100] Figure provided by Cliff Frohlich, Institute for Geophysics, The University of Texas at Austin.

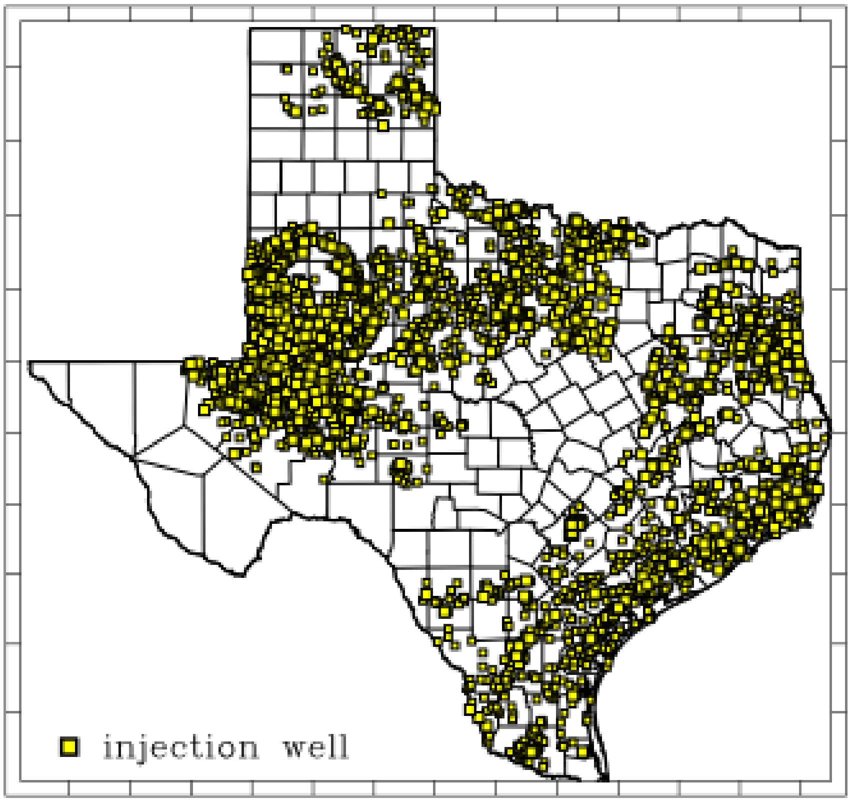

Figure 16: Injection Well Locations Across Texas

A few companies are investigating possible recycling opportunities, even creating pilot projects that could be initiated as soon as within the next year. Figure 17[101] shows the evaluation process that Pioneer Natural Resources is undergoing, to determine whether a centralized or mobile recycling facility would be feasible to accommodate their development sites. Other companies are faced with the issue of placement; their operations are spread out, therefore, trying to determine the optimal location for treatment facilities is challenging—due to both potentially high transportation costs to get wastewater to a centralized treatment facility and transportation costs associated with

[101] Dunkel, Michael. Evolution of Water Management in 2013: A Producers Perspective. *Pioneer Natural Resources.* Water Development for Shale Plays Conference. 02/26/13.

mobile treatment, in that the treated flowback water must be delivered to the designated site for further fracturing stimulation.

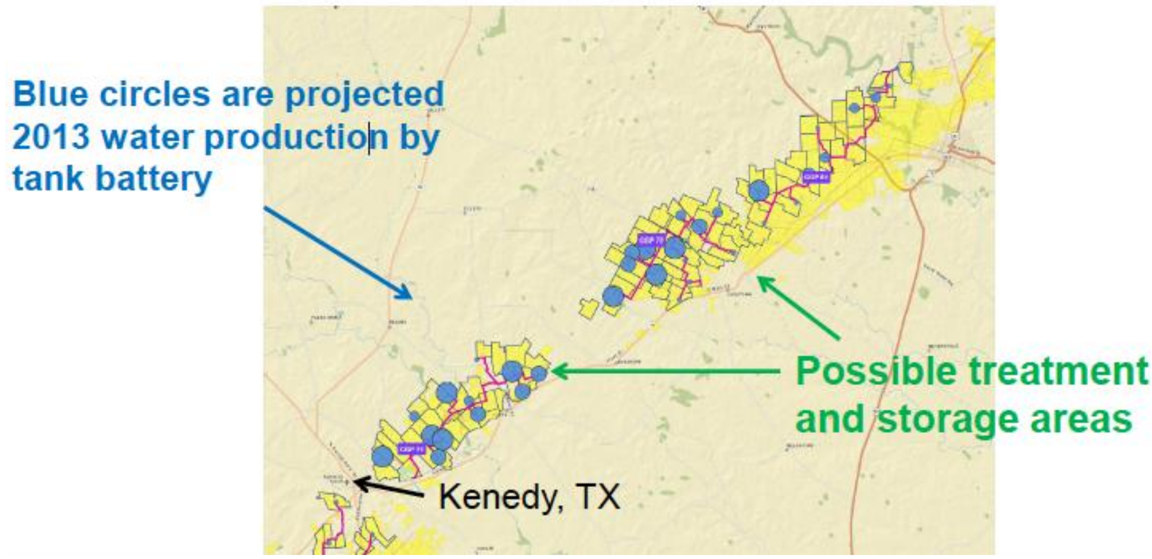

Figure 17: Pioneer Natural Resources' Analysis for Potential Recycling Efforts in the Eagle Ford

According to Michael Dunkel, Sustainable Development Director at Pioneer, a centralized facility would likely be too expensive—Pioneer's operations specifically are somewhat spread out and not enough wastewater is generated in the Eagle Ford play to make it logistically and economically feasible. However, a high capacity mobile system may be attractive, as it could be transferred between sites as needed and could simultaneously function as a storage facility as well.

4.3.3 Motivation for Implementation (or not) of Recycling Technologies

Motivations are variable, but largely consist of the following: 1) regulatory requirements; 2) logistics; 3) costs/economics of treatment versus disposal; and 4) community acceptance. Although all companies expressed concern for environmental responsibility, as well as desire to obtain community trust and support through sustainable development practices, cost and logistics of recycling were the overall determining factors. Without a change in regulatory stipulations, practices will likely remain the same—disposal through Class II wells and purchasing new fresh/saline water from local landowners.

To briefly summarize, large operators across the Eagle Ford have found disposal through injection within a Class II well to be the most optimal wastewater management strategy to date. Plans for future treatment and reuse efforts have been discussed, and perhaps even piloted; however, the economics still prevail, and without any sort of regulatory constraint on disposal, management strategies are expected to remain as they are.

5. DISCUSSION

By combining the statistics, trends, and supportive reasoning motivating current wastewater management efforts outlined above, predictions can be made as to the future direction wastewater management is headed in the Eagle Ford shale play.

5.1 Future Application in the Eagle Ford Shale

5.1.1 PROJECTED WATER USE IN THE EAGLE FORD

Water use in the Eagle Ford is projected to slowly increase and plateau over the next few decades due to development growth (although water use per well has actually decreased over recent years due to the increased use of gel fracture fluids, as discussed previously). This trend of increasing overall water use is not new; it has been occurring throughout the life of the play and is depicted in Figure 18[102], showing the dramatic shift in the spatial distribution of hydraulic fracturing operations and their subsequent water use from the year 2008 (left) to 2011 (right). As is readily apparent, water use due to hydraulic fracturing has increased dramatically in south Texas specifically over that three-year timeframe (signified by the large brown areas).

[102] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

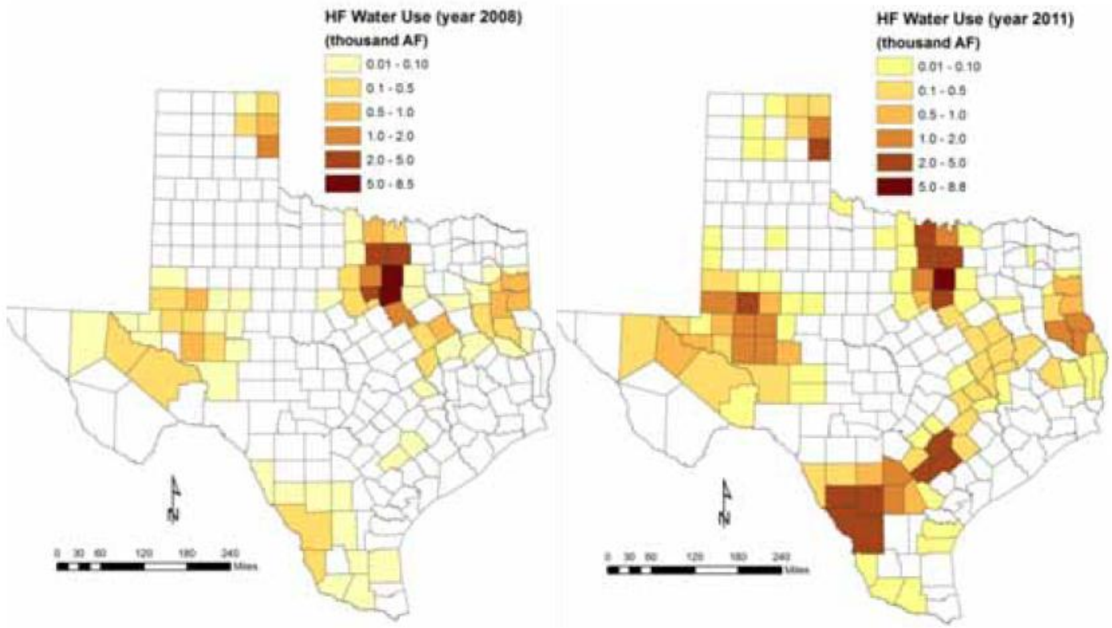

Figure 18: Spatial Distribution of Hydraulic Fracturing Water Use from 2008 (~36,000 AF) and 2011 (~81,500 AF)

Maintaining this trend, water utilization in the Eagle Ford is expected to continue to increase, although at a slower pace, over the next 10 years, peaking at 35 thousand acre-feet (approximately 11.4 billion gallons), and then begin to slowly decline after the year 2060[103], as development eventually begins to slow down. This water will come primarily from groundwater supplies—as very few available surface water supplies exist in this region.

5.1.2 Projected Water Quality Use in the Eagle Ford

Currently, approximately 20 percent of water used for fracture fluids in the Eagle Ford is brackish water. This trend of brackish water use is expected to not only continue

[103] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

in the Eagle Ford but to increase substantially throughout the coming years. It has been projected that brackish water use in hydraulic fracturing operations in this region will most likely increase to 40 percent by 2020 and reach 50 percent by 2060.[104] (To reiterate, brackish water is defined as water with greater than 1,000 mg/L TDS and generally less than 10,000 mg/L TDS, although some concentrations reach 35,000 mg/L TDS.) This number varies considerably among operators. During the interviews that were held (cited above), one company roughly estimated as much as 60 percent of water used in their operations today is classified as brackish (greater than 1,000 mg/L TDS).

All factors considered, brackish water use appears to hold the greatest potential for decreased fresh water demand in shale operations within the Eagle Ford. The recycling potential is low—even if all flowback and produced waters are treated and reused, operators will still have to procure at least 80 percent, but likely 90 percent, of water supplies to continue hydraulic fracturing development, which could total as much as 31,500 acre-feet or more (approximately 10.3 billion gallons) per year at peak use. Brackish water has the potential to dramatically decrease this need. If the projected 40 percent of fluids comprised of brackish water is achieved, approximately 14,000 acre-feet of fresh water would be displaced (4.6 billion gallons). This area of the state (specifically Region L) has more than ample supplies to accommodate this demand, with nearly 420 million acre-feet of brackish water supplies at less than 10,000 mg/L TDS (30,000 times the projected annual use by 2020).

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[104] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

5.1.3 PROJECTED RECYCLING OF FLOWBACK/PRODUCED WATER IN THE EAGLE FORD

Although roughly no recycling or reuse of flowback and produced waters is occurring in the Eagle Ford as of yet, this is projected to change slightly over the coming decades. According to Nicot et al., an estimate of approximately ten percent of water use for hydraulic fracturing will be made up of recycled wastewater by the year 2020; this number is expected to stay the same through 2060 as well.[105] With this estimated percentage, recycling and reuse can potentially displace as much as 500,000 gallons of fresh water per well with 2011 water use statistics—roughly 3,500 acre-feet per well in peak water use years or one billion gallons.

According to my analysis and interpretation, the ten percent estimation is likely high. Talking with operators, as well as Dr. Nicot (lead author of the BEG study), the estimate of 20 percent flowback/produced water production is quite optimistic—the real number is likely closer to ten percent of initial injected fluid volume. Therefore, to achieve the ten percent recycling figure, 100 percent of wastewater produced following fracturing stimulations would have to be treated or reused within the next seven years. This seems unlikely—without some sort of regulatory shift, requiring operators to recycle their wastewater. With such low volumes of wastewater production, coupled with widely available fresh water supplies and cheap disposal options, economic conditions for recycling are very difficult to achieve. Although a few companies are toying with pilot

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[105] Nicot, Jean-Philippe, et al. Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report. *Texas Oil and Gas Association, Austin, Texas.* September 2012.

treatment projects, with current conditions, a large shift in wastewater management methods is unlikely in the next decade.

5.1.4 Factors to Consider

When looking at whether an operator will recycle the flowback and produced waters generated during shale development, a number of factors come into play. These factors can be generally consolidated into four main categories: 1) cost; 2) logistics; 3) legal and regulatory stipulations; and 4) "license to operate"—essentially maintaining community support.

First, cost, as discussed previously, is of course a primary driver for operators. Although most companies would like to recycle for environmental responsibility or stewardship reasons etc., if the economics are not right—if recycling costs are much higher than other management options, for example disposal through injection—there will likely be little justification to incur the increased costs for treatment and reuse.

Second, logistics is another primary consideration—one that may even override costs if recycling is essentially not feasible with current operational layouts and demand. Logistically speaking, there are an additional four factors (among many others) to consider: 1) the treated water must be accumulated and stored in a central location to achieve economies of scale; 2) the wastewater water must be treated to a degree so as to not interfere with future hydraulic fracturing designs; 3) the water must be stored in some way until it is needed at a new well; and 4) both the produced water and treated water must be transported, either to the site of treatment, to the new site where it is needed, or both.[106] Because hydraulic fracturing processes require substantial water supplies in very short periods of time—on the order of days—the treated water must be accessible in an efficient and quick manner, so as to not disrupt or delay development activities.

Third, legal and regulatory issues play a role in this decision-making process—and perhaps the biggest role when it comes to recycling in the Eagle Ford (as it is readily apparent that recycling efforts may not be developed organically). This effect can be seen firsthand in the Marcellus shale, specifically in Pennsylvania, where the Pennsylvania Department of Environmental Protection made it a priority to recycle flowback and produced waters from hydraulic fracturing operations. Pennsylvania requires a "wastewater source reduction strategy" in 25 Pa. Code § 95.10, "under which operators 'must identify the methods and procedures the operator shall use to maximize the recycling and reuse of flow back and production fluid.'"[107] This was a result of the inability of municipal wastewater treatment plants to adequately treat the high salinities and other constituents found in shale development wastewaters. This same regulatory action has the potential to happen here in Texas as well.

A number of bills have already been proposed pertaining to hydraulic fracturing and flowback/produced water management. Should these rules be adopted, the wastewater management environment in nearly all shale plays across the State of Texas

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[106] Dunkel, Michael. Evolution of Water Management in 2013: A Producers Perspective. *Pioneer Natural Resources.* Water Development for Shale Plays Conference. 02/26/13.

[107] Wiseman, Hannah. UT Law Grid: Hydraulic Fracturing in Texas: The Changing Legal Landscape. *The University of Texas at Austin, Energy Center.* 01/22/13. Accessed on 03/27/13, http://www.utexas.edu/law/academics/centers/energy/2013/01/hydraulic-fracturing-in-texas-the-changing-legal-landscape/.

would have to change radically—especially in the Eagle Ford. Two in particular are already in the Texas Legislature:

1. House Bill (HB) No. 3537: "The commission shall adopt rules requiring that, to the extent practicable, flowback and produced water from an oil or gas well on which a hydraulic fracturing treatment has been performed be treated to a degree that would allow the fluid to be: 1) used to perform a hydraulic fracturing treatment on another well; 2) used for another beneficial purpose; or 3) discharged into or adjacent to water in the state."[108] If accepted, these rules shall be adopted by the RRC no later than December 1, 2013.
2. HB No. 3315: "It is the policy of this state that water produced in exploration, development and production of oil or gas or geothermal resources is a potential water source to address future water needs for Texas. The purpose of the chapter is to encourage reuse and recycling of water produced in connection with the exploration, development, and production of oil or gas or geothermal resources."[109] If the rule passes, it could be taken into effect immediately or at the latest, September 1, 2013.

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[108] Gutierrez. H.B. No. 3537, A Bill to be Entitled an Act. *Texas Legislature Online.* 83R2521 SMH-D. Accessed on 03/27/13, http://www.legis.state.tx.us/Search/DocViewer.aspx?K2DocKey=odbc%3a%2f%2fTLO%2fTLO.dbo.vwCurrBillDocs%2f83%2fR%2fH%2fB%2f03537%2f1%2fB%40TloCurrBillDocs&QueryText=hydraulic+fracturing&HighlightType=1.

[109] Keffer. H.B. No. 3315, A Bill to be Entitled an Act. *Texas Legislature Online.* Accessed on 03/27/13, http://www.legis.state.tx.us/Search/DocViewer.aspx?K2DocKey=odbc%3a%2f%2fTLO%2fTLO.dbo.vwCurrBillDocs%2f83%2fR%2fH%2fB%2f03315%2f1%2fB%40TloCurrBillDocs&QueryText=hydraulic+fracturing&HighlightType=1.

Although these rules, if adopted, would force operators to recycle waste fluids from their operations, from the operator perspective, regulatory bodies could first take action to incentivize recycling without mandating it. (Note, the following two recommendations were made from an industry representative.) First, the RRC could allow unrestricted brackish water use for oil and gas development activities.[110] Currently, the RRC requires a permit for wells associated with oil and gas activities that draw "saline or brackish water from underground reservoirs that are below the base of usable quality water".[111] Unrestricted use would decrease the amount of time and resources necessary to ensure regulatory compliance for the use of brackish water, encouraging this practice.

However, although allowing unrestricted brackish water use would make permitting processes easier on the operator, this may not be the ideal solution. There is little scientific study of what potential effects large withdrawals of brackish water from these aquifers could have on the surrounding fresh water formations.[112] Saltwater intrusion can happen when the extraction of groundwater results in a change of pressure within the aquifer, causing saltwater in an adjacent formation to intrude; this is especially common in coastal aquifers, where connectivity exists with seawater. Figure 19[113] below

[110] Dunkel, Michael. Evolution of Water Management in 2013: A Producers Perspective. *Pioneer Natural Resources.* Water Development for Shale Plays Conference. 02/26/13.
[111] Water Use in Association with Oil and Gas Activities Regulated by the Railroad Commission of Texas. *Railroad Commission of Texas.* Accessed on 04/08/13, http://www.rrc.state.tx.us/barnettshale/wateruse.php.
[112] Conversation with Dr. J.P. Nicot. 04/18/13. Held at the Bureau of Economic Geology.
[113] Saltwater Intrusion. *U.S. Geological Survey.* Accessed on 04/24/13, http://water.usgs.gov/ogw/gwrp/saltwater/fig4.html. (Figure modified from Reilly, T.E., 1993, Analysis of ground-water systems in

is a schematic of this process. Though this may not be the case, it is a risk, potentially contaminating heavily-relied upon freshwater aquifers in this region. It is an area that should be looked at in greater detail before greater large-scale brackish water use is encouraged.

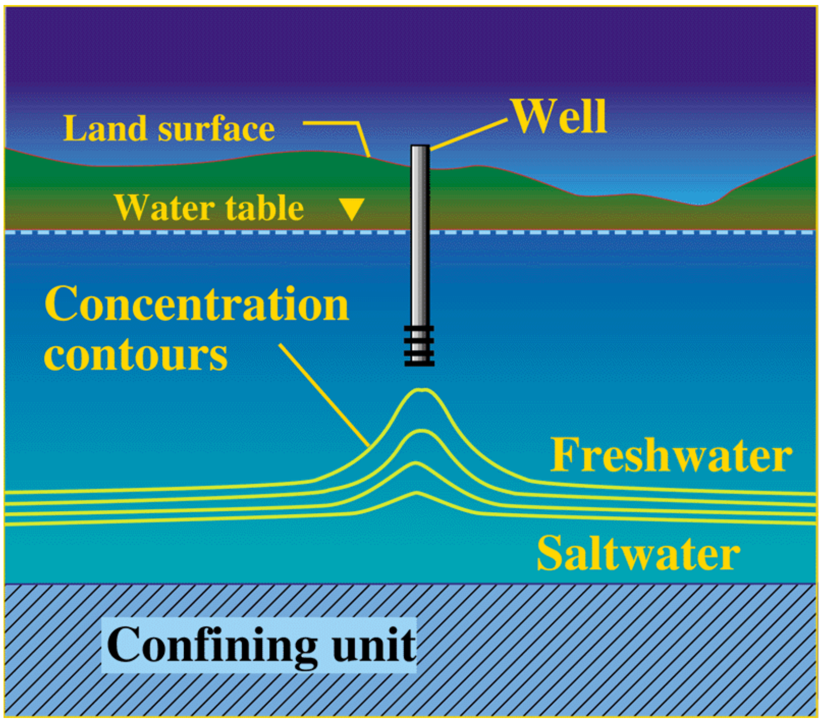

Figure 19: Saltwater Intrusion – Vertical Movement of Saltwater at a Discharging Well

Second, the RRC could speed approval for H11 permits required for produced water pits.[114] Often with flowback/produced water treatment facilities, a pit of some sort is necessary to temporarily store fluids, either produced water or treated water, until treatment or subsequent use is available. If the permit application process was conducted

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freshwater-saltwater environments, in Alley, W.M., ed., Regional ground-water quality: New York, Van Nostrand Reinhold, 634 p.)

[114] Dunkel, Michael. Evolution of Water Management in 2013: A Producers Perspective. *Pioneer Natural Resources.* Water Development for Shale Plays Conference. 02/26/13.

in a more timely manner, operators may be more willing to consider recycling options—as the regulatory requirements would be less demanding or prohibitive. However, budget constraints are probably a prevailing factor for the current speed of permit approval.

Clearly, there are many factors to be considered when determining whether recycling efforts are feasible with current and/or future operations; some of which are out of the operators' control—primarily regulation. In order for treatment and reuse opportunities to take place, clearly much time and dedication is required on the operator's side to determine the most optimal approach, all factors considered.

5.2 Application in Shale Plays Across the Country

As this was a case study, recognition of how this information can be transferred and applied to other shale plays across the country, and even the world, is necessary. Although many of the factors that play the largest role in the wastewater management strategies available for Eagle Ford operations are unique to the Eagle Ford—flowback/produced water volumes, local geology, available water supplies, regulatory culture, etc.—the methodology is still viable; these categories of factors can be taken and examined in each shale play to determine available and attractive wastewater management strategies personalized for each region.

It is well established that each shale play is unique, with varying formation characteristics, behaviors, and requirements, eliciting a customized development approach with every local. Wastewater management is no different. However, every play has the same opportunities to consider, such as the use of lower-quality water supply sources and installing treatment facilities to recycle and reuse flowback and produced waters. In order to complete a similar analysis in a different shale area, for example the Permian Basin in west Texas, one could start by looking at the basics of the formation—such as the volume of flowback and water requirements for stimulation—as well as current wastewater management strategies, availability of underground disposal, treatment through municipal wastewater facilities, and regulatory restrictions. With this information, a picture can be developed as to what is currently being done. Followed with interpretation and analysis, projections of prospective opportunities can then be made, recognizing the potential effects implementation of these opportunities may have on local water resources. This methodology is widely applicable to shale plays across the country and may be of help when considering realistic ways to make shale development processes more environmentally responsible and sustainable.

6. CONCLUSION

The application of hydraulic fracturing and horizontal drilling technologies to shale formations has revolutionized the resource outlook for the US, unlocking tremendous supplies of natural gas, condensates, and oil. However, these processes have also introduced several new environmental impacts.

Water management is a significant part of the entire shale development process, from sourcing water for fracture fluids to properly handling the wastewaters produced after the fracturing process. Hydraulic fracturing processes in the Eagle Ford require on average five million gallons of water per well, and with the nearly exponential increases in production currently taking place in this region, water demands have soared, putting stress on local water resources. However, there are ways for operators to decrease their water use—mainly recycling of flowback water for reuse in subsequent stimulations and alternative water sourcing.

Today, recycling of flowback fluids makes up only a fraction of total water use for shale development. Part of this is due to the complexity of the fluids and treatment technologies. Great and in-depth analyses go into determining the necessary treatment needed, the logistics of treatment and reuse, as well as overall costs of different management or disposal methods. Although in the past, cost has been pegged a primary determinant for the implementation of treatment facilities, recent investigations have shown the contrary, with additional benefits to be incurred with recycling efforts.

There are multiple benefits to recycling flowback and produced waters associated with hydraulic fracturing activities, including the following: 1) reduction of fresh water use—a shared resource; 2) reduction of trucks on the road; 3) reduction of water disposal; 4) potential technology or infrastructure benefits to local communities; and 5) potential long-term cost savings to the operator. However, these potential benefits do not come free of challenges; issues to overcome for successful recycling efforts include: 1) developing cost-effective methods; 2) potential environmental damage or contamination through transport of fluids, produced water storage, etc.; 3) regulatory stipulations; and 4) variability—of water quality, infrastructure, and hydraulic fracture design—between projects.

The Eagle Ford shale is a unique play with respect to water supply and wastewater management methods. Due to the region's fairly arid climate, currently 90 percent of water use is supplied by groundwater resources—primarily the Carrizo-Wilcox and Gulf Coast aquifers. Scare surface water resources within the region apparently supply the remaining ten percent. This water use amounted to approximately 25 thousand acre-feet of water in 2011. Of this water use, roughly 20 percent is classified as brackish water, greater than 1,000 mg/L TDS—displacing 5,000 acre-feet of fresh water. Essentially zero flowback/produced water recycling is happening in the Eagle Ford today. One primary reason for this is the fact that only 10 to 20 percent of the originally injected fracture fluid returns to the surface as flowback/produced water. This leaves little opportunity for robust recycling infrastructure, as well as limiting the ability for operators to achieve economies of scale with treatment facilities, making them economically attractive to pursue.

It has been projected that recycling efforts in the Eagle Ford may increase to ten percent of water use by 2020, although this figure is likely optimistic. Without some sort of regulatory requirement, companies are unlikely to implement recycling measures within this region, as currently there are widespread, cheap disposal options through Class II injection wells coupled with ample, affordable supplies of fresh water. However, there are other ways operators can decrease their demand for fresh water supplies—utilization of brackish water resources. Plentiful supplies of brackish water can be found across the Eagle Ford shale, as well as the State of Texas as a whole. Nearly 420 million acre-feet of brackish water has been estimated in Region L alone, approximately 400 million of which is between 1,000 and 3,000 mg/L TDS—a very manageable salinity. This resource is a very valuable asset, one that could drastically reduce the demand on fresh water in this region. If the projected estimates of 40 percent brackish water use become a reality by 2020, as much as 14,000 acre-feet of fresh water could be displaced (at peak water use)—4.6 billion gallons. However, due care must be given to ensure the integrity of surrounding freshwater aquifers is maintained throughout the extraction of brackish waters.

Although the recycling potential of the Eagle Ford is somewhat slim, primarily due to low flowback/produced water volumes found in this shale formation, all opportunities for reduction of fresh water demand are not lost. The use of brackish water supplies in place of fresh water has the potential to dramatically reduce the demand and stress on fresh water resources in this fairly dry region. The use of brackish water diminishes competition with surrounding municipalities and industry, decreases stresses placed on widely used and depended on fresh water aquifers—such as the Carrizo-Wilcox and Gulf Coast—and utilizes a fairly untapped resource. As development will likely continue at a rapid pace in order to extract the valuable resources within the Eagle Ford shale, continued innovation and commitment to the use of lower quality waters for hydraulic fracturing processes would dramatically alter the future of this play—enabling continued future development of these valuable resources in an environmentally and publically responsible way.

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